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 BAL-007-1 AND TOP-003-7

Shamai Elstein
Assistant General Counsel
Alain Rigaud
Associate Counsel
North American Electric Reliability Corporation
1401 H Street NW, Suite 410
Washington, D.C. 20005
202-400-3000
shamai.elstein@nerc.net
alain.rigaud@nerc.net

Counsel for the North American Electric Reliability Corporation

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5 of the regulations of the Federal Energy Regulatory Commission ("FERC" or "Commission"),[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval (1) proposed Reliability Standard BAL-007-1 Near-term Energy Reliability Assessments, (2) proposed Reliability Standard TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection, and (3) the proposed definitions of the terms Energy Reliability Assessment ("ERA") and Near-Term Energy Reliability Assessment ("Near-Term ERA") for inclusion in the *Glossary of Terms used in NERC Reliability Standards*.[4]

The proposed Reliability Standards would help address the reliability risks associated with inconsistent output from various energy resources, which, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the Bulk-Power System ("BPS") needed to serve electrical Demand, maintain sufficient Operating

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1 16 U.S.C. § 824o.

2 18 C.F.R. § 39.5 (2024).

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

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

Reserve, and ensure the reliable operation of the BPS. As discussed further below, to address this risk, proposed Reliability Standard BAL-007-1 would require Balancing Authorities to (1) perform ERAs in the operations planning time horizon to identify possible Energy Emergencies, and (2) develop and implement Operating Plans to minimize the risks of any forecasted Energy Emergency identified in the ERA. Modifications to the TOP-003 Reliability Standard are also proposed to provide Balancing Authorities with the ability to collect the data necessary to perform such assessments.

NERC requests that the Commission approve the proposed Reliability Standards and Glossary terms, provided in Exhibit A hereto, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests approval of the associated Implementation Plan (Exhibit B); the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (Exhibit E); and the retirement of currently-effective Reliability Standard TOP-003-6.1.

As required by Section 39.5(a) of the Commission's regulations,[5] this petition presents the technical basis and purpose of the proposed Reliability Standards, a summary of the development history (Exhibit F), and a demonstration that the proposed Reliability Standards meet the criteria identified by the Commission in Order No. 672[6] (Exhibit C). The NERC Board of Trustees adopted the proposed Reliability Standards on December 10, 2024.

I. SUMMARY

As the BPS becomes more reliant upon energy constrained and variable resources, planning methods and strategies need to be reevaluated to help ensure they identify energy-related risks to

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5 18 C.F.R. § 39.5(a).

6 *Rules Concerning Certification of the Electric Reliability Organization; and Procedures for the Establishment, Approval, and Enforcement of Electric Reliability Standards*, Order No. 672, 114 FERC 61,104 at PP 262, 321-37 (2006) [hereinafter Order No. 672], *order on reh'g*, Order No. 672-A, 114 FERC 61,328 (2006).

reliability. As noted above, inconsistent output from various energy resources, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the BPS needed to serve electrical Demand, maintain sufficient Operating Reserve, and ensure the reliable operation of the BPS. Traditional capacity-based planning methods and strategies may not identify these energy-related risks. For this reason, NERC, working with industry stakeholders, identified the need to modify its Reliability Standards to require energy-based planning methods and strategies that incorporate critical time-based variables that are not captured in capacity-based processes.

As discussed in detail herein, proposed Reliability Standard BAL-007-1 serves as a step in transitioning to energy-based planning methods in the operations planning time horizon. While many entities have already begun incorporating some energy-based planning methods and strategies, Reliability Standard BAL-007-1 would help achieve a level of consistency across the industry. A separate Reliability Standard development project (Project 2024-02 – Planning Energy Assurance) is underway to address energy-based planning methods and strategies in the long-term planning time horizon.[7]

The purpose of proposed Reliability Standard BAL-007-1 is to identify and minimize the risks of forecasted Energy Emergencies in the operations planning time horizon by analyzing the expected resource mix availability. It would require Balancing Authorities to perform Near-Term ERAs and have Operating Plans in place to identify and minimize the risks of forecasted Energy Emergencies. Near-Term ERAs would entail an assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and provide Operating Reserves for the

[7] The phrases "operations planning" and "long-term planning" are not NERC glossary terms but are referenced in the following NERC document: *Time Horizons*, at https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf.

BPS. As proposed, the assessment period would begin no later than two days after the operating day and have a minimum duration of five days and a maximum duration of six weeks. Proposed Reliability Standard TOP-003-7 would provide the Balancing Authority with specific authority to collect the data necessary to perform the Near-Term ERAs.

NERC respectfully requests that the Commission approve proposed Reliability Standards BAL-007-1 and TOP-003-7 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:[8]

Shamai Elstein*
Assistant General Counsel
Alain Rigaud*
Associate Counsel
North American Electric Reliability Corporation
1401 H Street NW
Suite 410
Washington, D.C. 20005
202-400-3000
Shamai.Elstein@nerc.net
Alain.rigaud@nerc.net

Soo Jin Kim*
Vice President, Engineering and Standards
Jamie Calderon*
Director, Standards Development
North American Electric Reliability Corporation
3353 Peachtree Road, N.E.
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560
Soo.jin.kim@nerc.net
Jamie.calderon@nerc.net

III. REGULATORY BACKGROUND

a. Regulatory Framework

By enacting the Energy Policy Act of 2005,[9] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk-Power System, and with the duty of certifying an ERO that would be charged with developing and enforcing

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[8] NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203, to allow the inclusion of more than two persons on the service list in this proceeding.

[9] 16 U.S.C. § 824o.

mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards.[10] Section 215(d)(5) of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard.[11] Section 39.5(a) of the Commission's regulations requires the ERO to file for Commission approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes to make effective.[12]

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA and Section 39.5(c) of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.[13]

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.[14] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[15] In its ERO

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10 *Id.* § 824(b)(1).
11 *Id.* § 824o(d)(5).
12 18 C.F.R. § 39.5(a).
13 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).
14 Order No. 672 at P 334.
15 The NERC Rules of Procedure are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at https://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf.

Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain criteria for approving Reliability Standards.[16] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders. Further, a vote of stakeholders and adoption by the NERC Board of Trustees is required before NERC submits the Reliability Standard to the Commission for approval.

c. The Need for Energy Assurance Reliability Standards

Fuel assurance and forward energy supply planning are increasingly important as the BPS transitions from coal and nuclear resources to wind, solar, natural gas, and hybrid resources. Historically, analysis of the resource adequacy of the BPS focused on capacity over peak time periods. Assessments of resource adequacy focused on capacity reserve levels compared to peak demand because resources were generally dispatchable and available when needed. This assumption was logical in the past as fuel availability was assured with either firm fuel contracts (commodity plus transportation capacity), or on-site storage (e.g., oil, coal, or reservoir-based hydro), or required periodic and predictable fuel replacement (e.g., nuclear). The transition to include more intermittent renewable energy resources is creating a more complex scenario and highlighting the need for energy assurance.

Energy assurance and fuel assurance risks are becoming more apparent as extreme weather has resulted in energy deficits, as opposed to capacity deficits, in recent years as multiple extreme

[16] ERO Certification Order at P 250.

events have jeopardized the BPS.[17] All of these conditions can cause fuel unavailability and, in turn, has led to operational uncertainty across the BPS.

For these reasons, NERC's Reliability and Security Technical Committee ("RSTC") formed the Energy Reliability Assessment Task Force ("ERATF") to assess risks associated with energy constrained resources. The ERATF assessed the risks associated with unassured energy supplies and analyzed and collaborated with stakeholders on the issues outlined in the "Ensuring Energy Adequacy with Energy-Constrained Resources" whitepaper.[18]

The ERATF identified concerns regarding energy sufficiency in the areas of operations, operations planning, and long-term planning time horizons. Specifically, the ERATF determined that due to the changing resource mix and frequency of extreme weather events, analysis of installed generating capacity alone was not sufficient to ensure a reliable supply of energy for the BPS.[19] Supply intermittency and demand volatility both require the dispatchable generating fleet to be available and flexible enough to respond when called upon. These factors can lead to unexpected and unstudied energy issues in non-peak hours, a risk that would not be identified by traditional analyses focusing on capacity across the peak demand periods.

The ERATF recommended that entities perform ERAs that analyze all hours of a given study period, rather than just capacity across the peak hours, to address risks associated with the intermittency of renewable generation, demand volatility, the need for sufficient flexibility from balancing generation resources, and the potential for natural gas supply interruptions to ensure entities accurately understand the potential risks.[20]

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17 *See* Event Reports: (1) Southwest Cold Weather Event (February 2011); (2) Polar Vortex Review (January 2014); (3) South Central Cold Weather Event (January 2018); (4) Cold Weather Outages in Texas and the South Central United States (February 2021), https://www.nerc.com/pa/rrm/ea/Pages/Major-Event-Reports.aspx.

18 *See* NERC *Ensuring Energy Adequacy with Energy Constrained Resources* White Paper (Dec. 2020) https://www.nerc.com/comm/RSTC/Documents/Energy_Adequacy_White_Paper.pdf.

19 *See Id.* at 4

20 *See Id.* at 5.

The ERATF noted that NERC Reliability Standards do not explicitly define or require ERAs (i.e., assessments of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the BPS).[21] The review also found that existing Reliability Standards do not address critical infrastructure interdependencies and their potential impacts on power generation, insufficient tools to model and forecast wind, solar and other renewables, and the lack situational awareness due to an assumption that fuel is available.[22] The ERATF recommended that new or modified Reliability Standards require ERAs to address these issues to identify and minimize forecasted energy risks.[23]

Additionally, in its "2021 ERO Reliability Risk Priorities Report,"[24] the NERC Reliability Issues Steering Committee ("RISC") identified risks related to energy security as a significant risk to the Bulk Electric System ("BES") that needs to be managed. The report specifically stated that three of the top four ranked risks are connected to energy security and assessment issues (i.e., changing resource mix, resource adequacy and performance, and critical infrastructure interdependencies).[25] These identified risks were consistent with the risks highlighted by the ERATF's review. The RISC recommended energy assurance metrics and development of Reliability Standards that require energy assessments. The RISC stated that "[t]he RSTC should develop methods, processes, tools, metrics, and/or standard authorization requests that are needed to address energy security."[26]

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21 *See* NERC Energy Assessment Technical Justification (May 2022) https://www.nerc.com/pa/Stand/Project202203EnergyAssurancewithEnergyConstrainedR/2022-03%20ERATF%20Technical%20Justification.pdf.

22 *See Id.* at 3-4.

23 *See Id.*

24 *See* NERC 2021 ERO Reliability Risk Priorities Report (Aug.2021) https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf.

25 *See Id.* Figure at 15.

26 *See Id.* at 25.

Based on these resources, the ERATF developed a technical justification document that proposed enhancements to the NERC Reliability Standards,[27] and lead to the development of the Standards Authorization Request ("SAR") for Project 2022-03 Energy Assurance with Energy-Constrained Resources Reliability Standard BAL-007-1.

d. Development of the Proposed Reliability Standards

NERC developed the proposed Reliability Standards using NERC's standards development process. This process included multiple public comment and ballot periods. Proposed Reliability Standards BAL-007-1 and TOP-003-7 were posted for a final ballot November 25 – December 6, 2024. BAL-007-1 passed final ballot with 81.31% approval and 88.68% quorum and TOP-003-7 passed final ballot with 85.56% approval and 87.01% quorum. The NERC Board of Trustees adopted proposed Reliability Standards BAL-007-1 and TOP-003-7 on December 10, 2024. A full summary of development is included in Exhibit F.

IV. JUSTIFICATION FOR APPROVAL: PROPOSED RELIABILITY STANDARD BAL-007-1

Proposed Reliability Standard BAL-007-1 would address the reliability concerns regarding energy sufficiency in the operations planning time horizon that were identified by the ERATF and RISC. Proposed Reliability Standard BAL-007-1 takes the recommendations of the ERATF and RISC to transition to energy-based planning methods and strategies that incorporate critical time-based variables that are not captured in capacity-based processes. The proposed standard requires Balancing Authorities to perform Near-Term ERAs in the operations planning time horizon that would emphasize modeling resource capabilities, fuel supplies, Energy transfer, and Transmission constraints. Proposed Reliability Standard BAL-007-1 would improve reliability by requiring Balancing Authorities to perform Near-Term ERAs in the operations planning time horizon to

[27] Energy Assessment Technical Justification, *supra* note 21.

identify possible Energy Emergencies and act when appropriate to minimize the risks of forecasted Energy Emergencies.

In this section, NERC provides an overview of the proposed Reliability Standard, with a summary of the supporting rationale. Additional information may be found in the Technical Rationale for Proposed Reliability Standard BAL-007-1, included as Exhibit D to this petition.

a. Proposed Definitions of Energy Reliability Assessment and Near-Term Energy Reliability Assessment

Proposed Reliability Standard BAL-007-1 uses the terms Energy Reliability Assessment ("ERA") and Near-Term Energy Reliability Assessment ("Near-Term ERA") proposed to be included in the NERC *Glossary*. The proposed definitions for the terms are as follows:

> **Energy Reliability Assessment (ERA)** – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.
>
> **Near-Term Energy Reliability Assessment** – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

The inclusion of the terms ERA and Near-Term ERA within the NERC *Glossary* would establish a consistent understanding of the meaning of the terms across all NERC Reliability Standards going forward and make clear what is expected when an ERA or Near-Term ERA is required by a Reliability Standard.

The definition for "Energy Reliability Assessment" describes the fundamental purpose of an energy assessment. Although BAL-007-1 is limited to the operations planning horizon, the ERA definition is drafted to allow for use of the term in Reliability Standards applicable to different time horizons. As defined, ERAs are intended to look at the wide variety of resources available to serve load. ERAs go beyond the scope of capacity assessments that have traditionally been performed to look more closely at energy needs, consistent with the reliability concerns raised by the ERATF and RISC.

The definition for "Near-Term Energy Reliability Assessment" was developed specifically for the type of ERA covered by proposed Reliability Standard BAL-007-1 (i.e., ERAs during the operations planning horizon). The Near-Term ERA definition specifies the timeframe for performing ERAs in the operations planning horizon. Near-Term ERAs are defined as ERAs beginning no later than two days after the operating day with a minimum duration of five days and a maximum duration of six weeks. The Standard Drafting Team determined that this timeframe was appropriate to have a clear distinction from the assessment performed under the TOP Reliability Standards (i.e., Real-Time and Day-Ahead) and to maintain the relevancy of the ERA.

The specified minimum and maximum duration provides Balancing Authorities flexibility to assess the energy landscape over a period of time that encompasses the energy risks that they deem to be pertinent. Certain factors, such as weather dependent resources, could drive the consideration for longer-duration assessments. Doldrums in wind and solar production will have a historical expectation for how long they typically last and should be considered when determining the minimum duration of the Near-Term ERA. Factors such as fuel replenishment (e.g., for oil and coal) or scheduling maintenance may also weigh in favor of a longer duration.

Other factors, such as fuel constraints, may weigh in favor of a shorter duration assessment for certain Balancing Authorities. Fuel constraints, specifically natural gas scheduling timelines, typically extend through a single day (e.g., today for tomorrow) during the week, and three-day strips over weekends. Holidays introduce a longer strip than the typical weekends. Five-day strips are traded at least once per year and sometimes more than once depending on where holidays fall on the calendar. Given different risks associated with different areas, the proposed definition and

Requirement R1 of proposed BAL-007-1, described below, give flexibility to Balancing Authority to choose a duration for Near-Term ERAs that best suits the needs of their area.

Finally, the specification that Near-Term ERAs have "an assessment period that begins no later than two days after the operating day" helps ensure that the data used in Near-Term ERAs is current. This language would prevent Balancing Authorities from performing all Near-Term ERAs in a single assessment at the start of a year or season, maintaining current, relevant, and useful information for the Balancing Authority to make informed decisions.

b. Title, Purpose, and Applicability

The title of proposed Reliability Standard BAL-007-1 is Near-term Energy Reliability Assessments. The purpose of proposed Reliability Standard BAL-007-1: "To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon." Proposed Reliability Standard BAL-007-1 would be applicable to Balancing Authorities as the Standard Drafting Team determined it was the most appropriate function to perform Near-Term ERAs. Balancing Authorities are the most appropriate function to implement an Operating Plan addressing supply contingencies and demand volatility because they are responsible for integrating resource plans ahead of time and maintaining Load-interchange-generation balance within their Balancing Authority area.

c. Requirement R1

Proposed Reliability Standard BAL-007-1 Requirement R1 requires that Balancing Authorities must, individually or jointly with other Balancing Authorities, document a process for conducting Near-Term ERAs. Proposed Requirement R1 would provide as follows:

R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a process for conducting Near-Term Energy Reliability Assessments (ERA). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The Near-Term ERA process shall account for:

1.1.1. Forecasted or assumed Demand profiles;

1.1.2. Resource capabilities and operational limitations, including fuel supply;

1.1.3. Energy transfers with other Balancing Authorities; and

1.1.4. Known Bulk Electric System (BES) Transmission constraints that limit the ability of generation to deliver their output to Load.

1.2. The Near-Term ERA process shall specify the duration of the Balancing Authority's Near-Term ERAs.

1.3. The Near-Term ERA process shall specify the frequency at which the Balancing Authority will conduct Near-Term ERAs, subject to the following:

1.3.1. Each Balancing Authority will conduct Near-Term ERAs for all time periods unless the Balancing Authority demonstrates, via a documented methodology, that a Near-Term ERA is not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s).

1.3.2. The documented methodology for identifying time periods for which the Balancing Authority will not conduct a Near-Term ERA must (i) define the criteria used to determine when there is a low risk of an Energy Emergency occurring, and (ii) account for the items listed in 1.1.1 – 1.1.4 and other conditions associated with Energy Emergencies.

Under Requirement R1, a Balancing Authority may perform the required Near-term ERAs for just its area or work with a group of Balancing Authorities to jointly perform Near-Term ERAs for all their areas together. This flexibility is consistent with existing partnerships (e.g., Reserve Sharing Groups or resource adequacy collaboratives) between Balancing Authorities that are used for other operations or planning activities and real-time operations. Should a deficiency be identified in the ERA, the Balancing Authority, regardless of whether they performed their assessment jointly or individually, are expected to utilize all their available resources, including those in other Balancing Authority areas, to address the deficiency.

The goal of the Near-Term ERA is to determine if sufficient energy is available to meet demand and reliably operate the BPS. Requirement R1 sets the basic requirement for performing Near-Term ERAs. Because of differences in resource mixes and demand profiles between Balancing Authority areas, rather than requiring a set of prescriptive elements to assess, each

Balancing Authority is provided with minimum assessment requirements which they must use to define the scope of their ERAs. This will improve reliability by allowing sufficient flexibility for the Balancing Authority to determine how to appropriately balance generation resources for their area, and scope of their models of resource capabilities, fuel supplies, Energy transfer, and Transmission constraints to account for the risks present in their areas.

Requirement R1.1 lists the minimum elements that Balancing Authorities must account for in their Near-Term ERAs. First (part R1.1.1), the Balancing Authority must account for forecasted or assumed Demand profiles. The Balancing Authority has flexibility to determine exactly how Demand will be modeled, including considerations of how demand response is treated. A Balancing Authority may choose to include market based or dispatchable demand response

Second (part R1.1.2), the Balancing Authority would need to account for resource capabilities and operational limitations, including fuel supply. The modeling of resource capabilities is a key component of ERAs. This modeling includes accounting for constrained fuel supplies, such as natural gas; inventoried fuels, such as oil, coal, liquefied natural gas, and some hydro; and just-in-time fuels, such as wind, solar, and run-of-river hydro. ERAs look at the production from generating resources over a period of time, which will impact their operation.

Third (part R1.1.3), the Balancing Authority would also model Energy transfers with other Balancing Authorities. This modeling is the interchange between areas that Balancing Authorities count on in their day-to-day operation of their systems.

Last (part R1.1.4), the Balancing Authority must account for known BES Transmission constraints that limit the ability of generation to deliver their output to load. When a system has a known constraint that causes area generation to be limited under certain specific conditions, and those conditions are expected to occur, then that generation should be reduced in the ERA when those conditions are expected to occur.

Requirement parts R1.2 and R1.3 address the duration and frequency of Near-Term ERAs. Under Requirement part R1.2, Balancing Authorities must document in their processes the duration of their Near-Term ERAs. Consistent with the Near-Term ERA definition, the assessment period may be as short as five days or as long as six weeks. As explained above, Balancing Authorities are provided flexibility to determine the duration of the assessment period based on the factors relevant to their area. The determination of the duration of the assessment period will be based on several factors, such as system or generation outage recall timing, accuracy of forecast information beyond the next few days, or lead time for fuel replenishment.

Requirement part R1.3 requires the Balancing Authority to specify the frequency at which it will conduct Near-Term ERAs. The default rule is that a Balancing Authority must perform a Near-Term ERA for all time periods. For example, a Balancing Authority may choose to perform a two-week long Near-Term ERA every two weeks. It could also perform a two-week long Near-Term ERA every week. Under either scenario, all time periods would be covered by a Near-Term ERA. A Balancing Authority could not, however, perform a two-week long Near-Term ERA every three weeks as there would be a gap in the time periods assessed. This default rule will improve reliability by ensuring that ERAs cover all time periods throughout the year and cover the entire assessment period, not just peak demand periods.

Understanding that there may be periods of low risk for Energy Emergencies, however, the proposed Reliability Standard provides for an exception to this default rule if the Balancing Authority demonstrates that a Near-Term ERA is not necessary for a specific time period. Requirement part R1.3.1 and R1.3.2 provide that each Balancing Authority would not be required to conduct Near-Term ERAs for specified time periods if it could demonstrate, via a documented methodology, that a Near-Term ERA is not necessary for the specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s). This demonstration may be accomplished via screening tools that evaluate the factors listed in parts R1.1.1-1.1.4 and show that the risk of an Energy Emergency is low for that period of time. This requires documentation of the methods used to make that determination as well as the evaluation of the factors considered.

d. Requirement R2

Proposed Reliability Standard BAL-007-1 Requirement R2 requires Balancing Authorities to develop a set of Scenarios (or a method for Scenario development) to be used in performing Near-Term ERAs. The use of Scenarios in the Near-Term ERA provides a mechanism for each Balancing Authority to stress the system to gauge whether an Energy Emergency may occur in its area. Proposed Requirement R2 would provide as follows:

R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a set of Scenarios, or a method for developing Scenarios, for use in performing Near-Term ERAs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. The set of Scenarios must include (i) a base Scenario with expected system conditions, and (ii) other Scenarios that stress the system due to the following conditions, as applicable to the Balancing Authority's system:

2.1.1. Higher than forecasted or assumed Demand profiles;

2.1.2. The effects of an energy supply contingency;

2.1.3. The effects of a fuel supply contingency; and

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the best information available at the time of Scenario development.

Requirement part R2.1, sets out the minimum requirements for the Scenarios. In addition to a base Scenario with expected system conditions, the Balancing Authority must use other

Scenarios that stress the system due to (1) higher than forecasted demand or assumed Demand profiles, (2) the effects of an energy supply contingency, (3) the effects of a fuel supply contingency, and (4) other stressed conditions that have a historic precedent of occurring. The Balancing Authority has discretion to develop the Scenarios based on the risks common in its area. Each of the Scenarios can be varied independently or in combination with each other. At least one parameter should be varied enough to stress the system to determine if the remaining available resources are robust enough to meet the Demand and Operating Reserves.

As explained in the Technical Rationale, a possible Scenario for Demand profiles would be raising Demand from a 50/50 profile to a higher profile, such as a 90/10 maximum load Scenario, to measure the impact to the system and determine if energy shortfalls are forecasted.

Other Scenarios must address supply side risks (parts R2.1.2 and R2.1.3). The Balancing Authority must develop a Scenario for an energy supply contingency that effectively removes energy resources from the base case. Typically, the results of the base Scenario will identify the largest source of energy, which would be removed from the energy supply contingency Scenario. Additionally, the Balancing Authority must develop a Scenario that removes a set of resources that are supplied by the same fuel supply. This Scenario is traditionally thought of as natural gas supplying multiple generating stations but may also be a set of wind turbines that are closely situated rendered unavailable or with limited production due to a storm or lull or the loss of energy from solar panels that are covered by snow or smoke from a fire.

Last, the Balancing Authority must develop a Scenario based on historical events that have stressed the system. This Scenario would be specific to the region, the time of year, the forecasted conditions, and any other expected conditions that the Balancing Authority deems relevant to include in the Near-Term ERA.

As noted, the Balancing Authority has the flexibility to determine which resource or set of resources are included in the Near-Term ERA. The choices by the Balancing Authority in developing Scenarios, however, must be identified and documented. This will improve reliability by ensuring that Balancing Authorities are considering a wide range of conditions and circumstances that can cause Energy Emergencies while providing the ERO the necessary oversight to understand and evaluate the Balancing Authorities Near-Term ERA process.

e. Requirement R3

Proposed Reliability Standard BAL-007-1 Requirement R3 requires Balancing Authorities to document at least one Operating Plan to implement in response to forecasted Energy Emergencies identified by a Near-Term ERA. Proposed Requirement R3 would provide as follows:

> R3. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document one or more Operating Plan(s) to implement in response to forecasted Energy Emergencies, including provisions for notification to their Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

The objective of these Operating Plans would be to avoid, or minimize the effects of, any forecasted Energy Emergency. The Operating Plans would ensure that if a Near-Term ERA shows that a Balancing Authority may have insufficient energy, they will have a list of actions to implement when appropriate. Operating Plans are expected to include actions that can be performed by the Balancing Authority within the near-term operations planning time horizon for which the Near-Term ERA is designed.

f. Requirement R4

Proposed Reliability Standard BAL-007-1 Requirement R4 requires the Balancing Authority to perform the Near-Term ERA according to the process developed in Requirement R1 and using the Scenarios developed under Requirement R2. Proposed Requirement R3 would provide as follows:

> R4. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, perform Near-Term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

g. <u>Requirement R5</u>

Proposed Reliability Standard BAL-007-1 Requirement R5 requires the Balancing Authority to implement its Operating Plan(s) when a forecasted Energy Emergency is identified in a Near-Term ERA. Proposed Requirement R5 would provide as follows:

> R5. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, implement its Operating Plan(s), as documented in Requirement R3, when Near-Term ERAs identify any of the following forecasted Energy Emergencies: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
>
> • Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B; or
>
> • Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B.

Requirement R5 specifies the two circumstances that would constitute a forecasted Energy Emergency for purposes of BAL-007-1. The requirement looks to the Energy Emergency Alert ("EEA") definitions in EOP-011, Attachment 1, Section B to use an established threshold for when an Operating Plan needs to be implemented to address risks identified in a Near-Term ERA.

There are three EEA levels in EOP-011, two of which are associated with forecasted Energy Emergencies and referenced in Requirement R5. While EOP-011 addresses these Energy Emergencies in the real-time horizon, the Energy Emergencies identified in Near-Term ERAs under the proposed Reliability Standard would be forecasted events. The objective of BAL-007-1 is to identify the possibility of an Energy Emergency in advance and implement an Operating Plan to help avoid or minimize the forecasted Energy Emergency before it gets to be an Energy Emergency in the next day and real-time timeframes.

h. Requirement R6

Proposed Reliability Standard BAL-007-1 Requirement R6 requires the Balancing Authority to periodically update and provide its Near-Term ERA process, Scenarios or methods for developing Scenarios, and Operating Plan(s) to its applicable Reliability Coordinator. Proposed Requirement R6 would provide as follows:

> R6. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, review, update, as necessary, and provide to the applicable Reliability Coordinator its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3, at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

Requirement R6 requires that the Balancing Authority review their process, Scenarios, and Operating Plans, developed under Requirements R1 through R3, to determine if any changes are needed. The Balancing Authority must also provide this documentation to its Reliability Coordinator at least once every 24 months. This requirement will improve reliability by ensuring Balancing Authorities continue to update and modernize their Near-Term ERA process, Scenarios or methods, and Operating Plans to address the most relevant risks at the time. It also ensures that Reliability Coordinators are aware of their Balancing Authorities Near-Term ERA process, Scenarios or methods, and Operating Plans and allows for collaboration, as appropriate.

i. Proposed Reliability Standard BAL-007-1 Relationship to Other Standards

While proposed Reliability Standard BAL-007-1 has similarities to other standards requiring assessment of system conditions, namely TOP-001, TOP-002, and EOP-011,[28] the proposed standard focuses on a different time horizon and energy risks that are not clearly addressed in those other standards. The BAL-007-1 standard looks at a near-term time horizon

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[28] These Reliability Standards are similar to BAL-007-1 as they require capability assessments and Operating Plans be developed and implemented to address reliability risks. However, TOP-001 requires Real-time assessments, TOP-002 requires Operating Plans for next-day operations to address potential System Operating Limit, and EOP-011 requires Operating Plans in place to mitigate active Energy Emergencies.

which is longer than the other operations planning and Real-Time assessment requirements in the TOP and EOP Reliability Standards.[29] Additionally, BAL-007-1 more specifically requires the Balancing Authority to look at energy risks over an assessment period rather than perform a capacity assessment generally used to comply with current standards.

TOP-001 and TOP-002 require assessments and Operating Plans but their requirements are limited to the Real-Time and the next day time horizons. BAL-007-1's proposed language extends this outlook to at least five days and up to six weeks ahead, giving Balancing Authorities (1) the ability to implement mitigation actions with longer lead times (e.g., reschedule outages, conserve consumable fuel, source additional fuel) and (2) enhanced situational awareness of potential reliability risks well in advance of the operating day.

While the TOP-002, EOP-011, and BAL-007-1 Reliability Standards would all require Operating Plans to minimize or mitigate identified reliability risks, they would differ in the types of actions that a Balancing Authority would include. As BAL-007-1 assesses a longer time horizon, the projected conditions are more uncertain, and the Operating Plans developed should reflect that uncertainty. Instead of identifying specific actions that must be taken, the Operating Plans under BAL-007-1 may have more general processes than Operating Plans developed under TOP-002 or EOP-011. BAL-007-1 Operating Plans are not intended to replace TOP-002 and EOP-011 Operating Plans but to identify additional actions that can be implemented when potential risks are identified with a longer lead time. The goal of these longer-term Operating Plans is to reduce the likelihood or the severity of an actual Energy Emergency occurring, which would require an EOP-011 Operating Plan. Actions that are taken as outlined in a BAL-007-1 Operating

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[29] *See e.g.,* TOP-001 Requirements R9; TOP-002 Requirements R1, R2, R3, R4, R5, R6, and R7; EOP-011 Requirements R1, R2, R3, R4, R7, and R8.

Plan would then lead into the day-ahead Operating Plans and in Real-time, through the establishment of more favorable initial conditions, rather than overlapping them.

Also, while EOP-011 Requirement R2 includes Energy Emergencies as a risk that Operating Plans must address, these assessments have generally been performed as capacity assessments, or potentially a series of capacity assessments in succession, which do not necessarily include variable energy and fuel risk, especially over a longer period. Proposed Reliability Standard BAL-007-1 explicitly requires accounting for these elements in an assessment and sets criteria regarding when risks need to be addressed through Operating Plans.

V. JUSTIFICATION FOR APPROVAL: PROPOSED RELIABILITY STANDARD TOP-003-7

The modifications in proposed Reliability Standard TOP-003-7 would ensure that Balancing Authorities have the necessary data to perform the Near-Tear ERAs. Currently, TOP-003-6.1, Requirement R2 requires the Balancing Authority to "maintain a documented specification for the data necessary for it to perform its analysis functions and Real-time monitoring." Requirement R5 of TOP-003-6.1 then requires relevant entities to provide that data to the Balancing Authorities. Proposed Reliability Standard TOP-003-7 adds Near-Term ERAs to the list of activities in Requirement R2 for which Balancing Authorities must have documented data specifications to collect data from relevant entities. Adding Near-Term ERAs to this list of activities would ensure Balancing Authorities can obtain the necessary data to perform Near-Term ERAs.

In this section, NERC provides an overview of the changes to the proposed Reliability Standard, with a summary of the supporting rationale.

a. Requirements

Proposed Reliability Standard TOP-003-7 only proposes revisions to Requirements R2 and R4 to add the proposed term Near-Term ERA to the list of activities for which the Balancing Authority is required to maintain and distribute data specifications to support its analysis functions. The Proposed Requirements R2 and R4 would provide as follows, respectively:

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions~~, and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions~~, and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

Under proposed Requirements R2 and R4, Balancing Authorities would be required to have data specifications for the information necessary to perform their Near-Term ERA. Requirement R5 remains unchanged from the currently effective version of the standard and requires that each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification in Requirement R4 to satisfy data specification requests from the Balancing Authority. Adding Near-Term ERAs to Requirements R2 and R4 would improve reliability by addressing the concern that Balancing Authorities may not have the authority gather the data and information necessary to complete their Near-Term ERAs.

VI. ENFORCEABILITY OF PROPOSED RELIABILITY STANDARDS

The proposed Reliability Standards also include measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[30] Additionally, the proposed Reliability Standards include VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standards. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. Exhibit E provides a detailed review of the VRFs and VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines.

VII. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed Reliability Standards to become effective as set forth in the proposed Implementation Plan, provided in Exhibit B hereto. The proposed Implementation Plan provides that the proposed Reliability Standard BAL-007-1 shall become effective on the first day of the first calendar quarter that is 24 calendar months after the effective date of the Commission's order approving the proposed Reliability Standard. This will allow Balancing Authorities time to develop their Near-Term ERA and Operating Plan procedures and request the data necessary to implement them.

The proposed Implementation Plan provides that the proposed Reliability Standard TOP-003-7 and the proposed definitions of Energy Reliability Assessment and Near-Term Energy Reliability Assessment shall become effective on the first day of the first calendar quarter that is 18 calendar months after the effective date of the Commission's order approving the proposed

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[30] Order No. 672 at P 327.

Reliability Standard. This will allow a 6-month time period for entities to collect the data necessary to perform a Near-Term ERA and provide it to their Balancing Authority before BAL-007-1 goes into effect. Currently effective Reliability Standard TOP-003-6.1 would be retired immediately prior to the effective date of proposed Reliability Standard TOP-003-7.

Following implementation of the proposed Reliability Standards, NERC will work with the Regional Entities and Balancing Authorities to assess the effectiveness of the proposed Reliability Standards in addressing the energy-related risks discussed in this petition. This effort may include evaluations of the implementation of the Balancing Authorities' Near-Term ERA process to determine if energy risks are appropriately identified and mitigated before Energy Emergencies occur. The ERO Enterprise will also assess the potential burden on entities performing and providing data for the ERAs. Using this feedback, the ERO Enterprise, working with stakeholders, will determine whether any modifications to the proposed Reliability Standard are necessary.

VIII. CONCLUSION

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

- proposed Reliability Standards BAL-007-1 and TOP-003-7, proposed definitions of Energy Reliability Assessment and Near-Term Energy Reliability Assessment, and associated elements included in Exhibit A, effective as proposed herein;
- the proposed Implementation Plan included in Exhibit B; and
- the retirement of Reliability Standard TOP-003-6.1 effective as proposed herein.

Respectfully submitted,

/s/ Alain Rigaud

Shamai Elstein
Assistant General Counsel
Alain Rigaud
Associate Counsel
North American Electric Reliability Corporation
1401 H Street NW, Suite 410
Washington, D.C. 20005
202-400-3000
shamai.elstein@nerc.net
alain.rigaud@nerc.net

Counsel for the North American Electric Reliability Corporation

Date: January 6, 2025

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A

Proposed Reliability Standards

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-1

Proposed Reliability Standard BAL-007-1

Standard Development Timeline

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

Description of Current Draft

The BAL-007-1 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024
45-day formal comment period with additional ballot	May 7 – June 20, 2024
45-day formal or informal comment period with additional ballot	September 19 – November 4, 2024

Anticipated Actions	Date
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 10, 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Near-term Energy Reliability Assessments
2. **Number:** BAL-007-1
3. **Purpose:** To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
5. **Effective Date:** See Implementation Plan for BAL-007-1.

B. Requirements and Measures

R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a process for conducting Near-Term Energy Reliability Assessments (ERA). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The Near-Term ERA process shall account for:

1.1.1. Forecasted or assumed Demand profiles;

1.1.2. Resource capabilities and operational limitations, including fuel supply;

1.1.3. Energy transfers with other Balancing Authorities; and

1.1.4. Known Bulk Electric System (BES) Transmission constraints that limit the ability of generation to deliver their output to Load.

1.2. The Near-Term ERA process shall specify the duration of the Balancing Authority's Near-Term ERAs.

1.3. The Near-Term ERA process shall specify the frequency at which the Balancing Authority will conduct Near-Term ERAs, subject to the following:

1.3.1. Each Balancing Authority will conduct Near-Term ERAs for all time periods unless the Balancing Authority demonstrates, via a documented methodology, that a Near-Term ERA is not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s).

1.3.2. The documented methodology for identifying time periods for which the Balancing Authority will not conduct a Near-Term ERA must (i) define the criteria used to determine when there is a low risk of an Energy Emergency occurring, and (ii) account for the items listed in 1.1.1 – 1.1.4 and other conditions associated with Energy Emergencies.

M1. Each Balancing Authority shall have evidence that it documented a process for conducting Near-Term ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a set of Scenarios, or a method for developing Scenarios, for use in performing Near-Term ERAs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. The set of Scenarios must include (i) a base Scenario with expected system conditions, and (ii) other Scenarios that stress the system due to the following conditions, as applicable to the Balancing Authority's system:

2.1.1. Higher than forecasted or assumed Demand profiles;

2.1.2. The effects of an energy supply contingency;

2.1.3. The effects of a fuel supply contingency; and

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.

M2. Each Balancing Authority shall have evidence that it documented the Scenarios, or the method of developing Scenarios, for use in performing Near-Term ERAs.

R3. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document one or more Operating Plan(s) to implement in response to forecasted Energy Emergencies, including provisions for notification to their Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it documented its Operating Plan(s) in accordance with Requirement R3.

R4. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, perform Near-Term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall have evidence that it performed the Near-Term ERAs in accordance with Requirement R4.

R5. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, implement its Operating Plan(s), as documented in Requirement R3, when Near-Term ERAs identify any of the following forecasted Energy Emergencies: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B; or
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B.

M5. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) in accordance with Requirement R5.

R6. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, review, update, as necessary, and provide to the applicable Reliability Coordinator its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3, at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have evidence that it reviewed and provided its Near-term ERA process, Scenarios or methods, and Operating Plan(s) to its Reliability Coordinator, in accordance with Requirement R6.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Balancing Authority shall keep data or evidence to show compliance with applicable requirements for six months for Near-Term ERAs or since the last audit.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 or Part 1.2.	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 through Part 1.2. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for one of the elements in Requirement R1 Part 1.3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.
R2.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include one of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include two of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include three of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include any of the conditions listed in Requirement R2 Part 2.1. OR The Balancing Authority failed to document a set of Scenarios or a method of developing

				Scenarios for use in performing Near-Term ERAs.
R3.	N/A	N/A	The Balancing Authority documented an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs.
R4.	N/A	N/A	N/A	The Balancing Authority failed to perform a Near-Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.
R5.	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a Near-Term ERA identified any of the forecasted conditions in Requirement R5.
R6.	N/A	N/A	The Balancing Authority reviewed information that contained the Near-Term ERAs process, the Scenarios or methods, and Operating	The Balancing Authority failed to review, update, and provide the Near-Term ERAs process, the Scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.

			Plan(s) but failed to update within 24 months.	

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan
- NERC Project 2022-03 Technical Rationale
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
1	TBD	NERC Project 2022-03 energy assurance new standard.	New

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-2

Proposed Reliability Standard TOP-003-7 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

The TOP-003-7 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	September 19 – November 4, 2024

Anticipated Actions	Date
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 10, 2024

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

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

Term(s):

The term Near-Term Energy Reliability Assessment refers to the proposed definition being developed under the Project 2022-03 Energy Assurance. As of this posting, the proposed definition of Near-Term Energy Reliability Assessment is:

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-7

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-03.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following.

1.5.1. Specified deadlines or periodicity which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Provisions to update or correct data and information, as applicable or necessary;

1.5.4. A mutually agreeable format;

1.5.5. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following.

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Provisions to update or correct data and information, as applicable or necessary.

2.5.4. A mutually agreeable format.

2.5.5. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

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

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

Each responsible 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 shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.

- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator,

Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

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

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R4 VSLs only, the intent of the Standard Drafting Team (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	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4	The responsible entity receiving a specification(s) in Requirement R3 or R4	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	satisfied the obligations in the specification but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	satisfied the obligations in the specification but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	in the specification but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

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		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP- 003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No.RD23-6-000,	

6.1	November 3, 2023	Effective Date	July 1, 2025
7	TBD	Energy Assurance Modifications – Addition of Near-Term ERA.	Revised

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-3

Proposed Reliability Standard TOP-003-7 Redline

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-7~~6.1~~

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project ~~2021-06~~2022-03.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes at a minimum the following.

1.5.1. Specified deadlines or periodicity which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Provisions to update or correct data and information, as applicable or necessary;

1.5.4. A mutually agreeable format;

1.5.5. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following.

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Provisions to update or correct data and information, as applicable or necessary.

2.5.4. A mutually agreeable format.

2.5.5. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real- time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

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

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

Each responsible 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 shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions,~~ and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions,~~ and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3 Compliance Monitoring and Enforcement Program: ~~As defined in the NERC Rules of Procedure,~~ “Compliance Monitoring and Enforcement Program” or “CMEP” means, depending on the context (1) the NERC Compliance Montioring and Enfrocement Program (Appendix 4C to the ~~refers~~ to the NERC Rules of Procedure) or the Commission approved program ~~identification~~ of ~~the processes~~aRegional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that is responsible ~~will be used to evaluate data or information~~ for performing compliance monitoring and enforcement activities~~the purpose of assessing performance or outcomes~~ with respect to Registered Entities compliance with Reliability Standards.~~the associated reliability standard.~~

Violation Severity Levels

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	Lower	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.
R2	Operations Planning	Lower	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions,~~ and~~ Real- time monitoring, and	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions,~~ and~~ Real- time	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions,~~ and~~ Real- time monitoring,	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions,~~ and~~ Real- time monitoring, and

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Near-Term Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	and Near-Term Energy Reliability Assessments.	Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions, ~~and~~ Real- time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 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	Lower	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	Operations Planning	Lower	The Balancing Authority did not distribute its Specification(s) to one	The Balancing Authority did not distribute its Specification(s) to two	The Balancing Authority did not distribute its Specification(s) to three	The Balancing Authority did not distribute its Specification(s) to four or

R#	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments.	entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments.	entities, or more than10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments.	more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments.
R5	Operations Planning, Same-Day Operations, Real-time Operations	Medium	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

2 Regional Variances

None.

3 Interpretations

None.

4 Associated Documents

None.

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		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP- 003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23,2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No.RD23-6-000,	

6.1	November 3, 2023	Effective Date	July 1, 2025

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit B

Implementation Plan

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2022-03 Energy Assurance with Energy-Constrained Resources | Reliability Standards BAL-007-1 and TOP-003-7

Applicable Standards

- BAL-007-1 – Near-term Energy Reliability Assessments
- TOP-003-7 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement

- TOP-003-6.1 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Transmission Operator
- Generator Owner
- Generator Operator
- Transmission Owner
- Distribution Provider

Terms in the NERC Glossary of Terms

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

Proposed New Definitions:

Energy Reliability Assessment:	Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand

	and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.
Near-Term Energy Reliability Assessment:	An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

Background

Energy assurance is an increasingly important aspect of a reliable Bulk-Power System (BPS) but has been inconsistently defined and measured without explicit standards. Project 2022-03 Energy Assurance with Energy-Constrained Resources was initiated to address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Reliability Standard BAL-007-1 – Energy Reliability Assessments is focused on the operations planning time horizon.

Effective Dates

BAL-007-1 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard BAL-007-1 shall become effective on the first day of the first calendar quarter that is 24 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 24 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definitions

Where approval by an applicable governmental authority is required, the definitions of Energy Reliability Assessment and Near-term Energy Reliability Assessment 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 definitions, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definitions of Energy Reliability Assessment and Near-term Energy Reliability Assessment shall become effective on the first day of the first calendar quarter that is 18 months after the date the definitions are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-003-7 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard TOP-003-7 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.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C

Order No. 672 Criteria

EXHIBIT C

Order No. 672 Criteria

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

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

The Proposed Reliability Standards BAL-007-1 Near-term Energy Reliability Assessments and TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection would advance the reliability of the Bulk-Power System ("BPS") by addressing the reliability risks associated with inconsistent output from various energy resources, which, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the BPS needed to serve electrical Demand, maintain sufficient Operating Reserve, and ensure the reliable operation of the BPS.

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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.").

Proposed Reliability Standards BAL-007-1 would require Balancing Authorities to (1) perform Energy Reliability Assessments ("ERA") in the operations planning time horizon to identify possible Energy Emergencies, and (2) develop and implement Operating Plans to minimize the risks of any forecasted Energy Emergency identified in the ERA.

Proposed Reliability Standard TOP-003-7 contains revisions to provide Balancing Authorities with the ability to collect the data necessary to perform such assessments.

The Proposed Reliability Standards would require Balancing Authorities to perform Near-Term ERAs and have Operating Plans in place to identify and minimize the risks of forecasted Energy Emergencies. Near-Term ERAs would entail an assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the BPS.

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

The proposed Reliability Standard is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. Proposed Reliability Standard BAL-007-1 would apply to Balancing Authorities. Proposed Reliability Standard TOP-003-7 would apply to Transmission Operators, Balancing Authorities, Generator Owners, Generator Operators, Transmission Owners, and Distribution Providers.

The proposed Reliability Standards clearly articulates the actions that applicable entities must take to comply with the standards.

[3] *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.").

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

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for the proposed Reliability Standard 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 Standard includes clear and understandable consequences in accordance with Order No. 672.

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

The proposed Reliability Standards contains measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements would be enforced and help ensure that the requirements would be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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[4] *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.").

[5] *See* Order No. 672, *supra* note 1, at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

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

The proposed Reliability Standards achieves its reliability goals effectively and efficiently in accordance with Order No. 672. Proposed Reliability Standard BAL-007-1 would provide robust and technically justified requirements for Balancing Authorities to perform Near-Term ERAs that would emphasis modeling resource capabilities, fuel supplies, Energy transfer, and Transmission constraints to identify possible Energy Emergencies in the operations planning time horizon. Proposed Reliability Standard BAL-007-1 would improve reliability by requiring Balancing Authorities to perform Near-Term ERAs in the operations planning time horizon to identify possible Energy Emergencies and take action when appropriate to minimize the risks of forecasted Energy Emergencies.

Proposed Reliability Standard TOP-003-7, which is only minimally revised to provide the Balancing Authority with specific authority to collect the data necessary to perform the Near-Term ERA, would continue to achieve its reliability goals 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.[7]

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[6] *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.").

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

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

The proposed Reliability Standard does not reflect a "lowest common denominator" approach. In accordance with the Commission's direction in Order No. 901, proposed Reliability Standard BAL-007-1 would improve reliability by requiring Balancing Authorities to perform Near-Term ERAs in the operations planning time horizon to identify possible Energy Emergencies and take action when appropriate to minimize the risks of forecasted Energy Emergencies.

Proposed Reliability Standard TOP-003-7 is only minimally revised to provide the Balancing Authority with specific authority to collect the data necessary to perform the Near-Term ERA.

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

The proposed Reliability Standards would apply consistently throughout North America and would not favor one geographic area or regional model.

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

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

The proposed Reliability Standard would have no undue negative effect on competition and would not unreasonably restrict the available transmission capacity or limit the use of the BPS in a preferential manner. The reliability need for ERAs (proposed BAL-007-1) is well documented in multiple NERC resources and disturbance reports. Proposed Reliability Standard TOP-003-7 revised applicability is supported by ensuring that Balancing Authorities have authority to collect the data necessary to perform the Near-Term ERAs.

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

The implementation plan for the proposed Reliability Standards is just and reasonable and appropriately balances the urgency in the need to implement the standard against the reasonableness of the time allowed for those who must comply to develop necessary procedures or other relevant capability. The proposed Implementation Plan provides that the proposed Reliability Standard BAL-007-1 shall become effective on the first day of the first calendar quarter that is 24 calendar months after the effective date of the Commission's order approving the proposed Reliability Standard. This will allow Balancing Authorities time to develop their Near-Term ERA and Operating Plan procedures and request the data necessary to implement them.

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9 *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.").

10 *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.").

The proposed Implementation Plan provides that the proposed Reliability Standard TOP-003-7 and the proposed definitions of Energy Reliability Assessment and Near-Term Energy Reliability Assessment shall become effective on the first day of the first calendar quarter that is 18 calendar months after the effective date of the Commission's order approving the proposed Reliability Standard. This will allow a 6-month time period for entities to collect the data necessary to perform a Near-Term ERA and provide it to their Balancing Authority before BAL-007-1 goes into effect.

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

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

[11] *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.").

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

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

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

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

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[12] *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.").

[13] *See* Order No. 672, *supra* note 1, at P 323 ("In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed.").

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Exhibit D

Technical Rationale

Technical Rationale

Project 2022-03 Energy Assurance with Energy-Constrained Resources
Reliability Standard BAL-007-1 | September 2024

BAL-007-1– Near-term Energy Reliability Assessments

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard BAL-007-1. It provides stakeholders and the Electric Reliability Organization (ERO) Enterprise with an understanding of the technical requirements in the Reliability Standards. This Technical Rationale and Justification for BAL-007-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Updates to this document include the Project 2022-03 Energy Assurance with Energy-Constrained Resources Drafting Team's (DT's) intent in drafting new requirements.

Overview

Inconsistent output from variable energy resources, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the Bulk Power System (BPS) needed to serve electrical Demand, maintain sufficient Operating Reserve, and ensure the reliable operation of the BPS. As part of ongoing operations planning, many entities have started incorporating some limited studies of energy reliability assessments that produce key metrics; however, there is inconsistency among entities on how the assessments are performed. To achieve the level of consistency needed across the industry, to reliably predict the energy needed to serve the load, energy reliability assessments for the operations time horizon and the minimization of identified risks are mandated and codified in this new standard. Project 2022-03 proposes two new Reliability Standards, BAL-007-1 and the Energy Reliability Assessment (ERA) definition. The purpose of the proposed Reliability Standard BAL-007-1 is to identify and minimize the risks of forecasted Energy Emergencies in the operations planning time horizon by analyzing the expected resource mix availability.

Rationale for BAL-007-1

As the BPS becomes more reliant upon energy constrained and variable resources, traditional capacity-based planning methods and strategies are being stretched and potentially do not identify energy-related risks to reliably operate and maintain the system. BAL-007-1 is being proposed as a step toward reducing these potential risks and to begin the transition to energy-based planning methods and strategies that incorporate critical time-based variables that are not captured in capacity-based processes.

BAL-007-1 is intended to provide Balancing Authorities (BAs) with the tools necessary to successfully navigate a system that has both variable load and resources.

BAL-007-1 Operating Plan(s), which are not intended to replace or supersede TOP-002 and EOP-011 Operating Plans, are intended to provide a list of actions over a longer-term/earlier time period that can reduce the severity of or fully mitigate the need to implement TOP-002 and/or EOP-011 plans.

The new Reliability Standard can be separated into three basic activities:

- Developing and documenting an ERA process, Scenarios or a method for creating them, and Operating Plans (Requirements 1-3).
- Performing ERAs as documented (Requirement 4).
- Comparing to forecasted Energy Emergency conditions and, if identified, implementing Operating Plan(s) in response to energy reliability risks (Requirement 5).

The purpose of the standard is to assess energy risk in the Operations Planning time horizon, determine if the identified risks are acceptable, and take action when appropriate. It should be noted that the standard offers the flexibility to allow for either a deterministic or probabilistic implementation of an ERA process. This has been left up to the BA to determine which method is right for their region. This standard improves reliability through identifying energy risks earlier and being able to implement longer lead time activities to mitigate those risks.

Relationship to Other Standards

While the proposed standard has similarities to other standards, especially TOP-001, TOP-002, and EOP-011, the proposed standard addresses reliability risks due to gaps in the existing reliability standards by focusing on different time horizons than current standards and energy risks which are not clearly addressed. In many cases, the language is intentionally similar to language in those requirements but applicable to different time horizons. The BAL-007-1 standard looks at a near-term time horizon which is longer than other operations planning assessment requirements. In terms of addressing energy risks, BAL-007-1 more clearly outlines the assessment requirements to look at energy over an assessment period rather than capacity assessments generally used to comply with current standards.

TOP-001 and TOP-002 provide requirements for assessments and Operating Plans in real-time and operations planning time horizons, but their requirements are limited to, at most the next day, which limits the options that Balancing Authorities may take to respond. BAL-007-1's proposed language extends this outlook to at least greater than five days and up to six weeks ahead, so BAs have time to implement mitigation actions with longer lead times (e.g., reschedule outages, conserve consumable fuel, source additional fuel) and have better situational awareness of potential reliability risks.

TOP-002, EOP-011, and BAL-007-1 all require Operating Plans to minimize or mitigate reliability risks, but they would likely differ in what actions that a BA would deem appropriate to be included in each. Since BAL-007-1 is assessing a longer time horizon, the projected conditions are more uncertain, and the Operating Plans developed should reflect that. Instead of identifying specific actions that must be taken, the Operating Plans under BAL-007-1 are expected to have more general processes than Operating Plans in TOP-002. BAL-007-1 Operating Plans are not intended to replace TOP-002 and EOP-011 Operating Plans but to identify

additional actions that can be implemented when potential risks are identified with a longer lead time and with an energy component of the assessment. The goal of these longer-term Operating Plans is to reduce the likelihood, or the severity of, an actual Energy Emergency occurring, which would require an EOP-011 Operating Plan. Actions that are taken as outlined in the BAL-007-1 Operating Plans would then lead into the day-ahead Operating Plans and real time, through the establishment of more favorable initial conditions, rather than overlapping them. An example timeline of how BAL-007-1 and EOP-011 would interact is shown below in *Figure 1* when the TOP-002 associated Operating Plans are not sufficient to avoid an Energy Emergency. Ideally, the longer-term Operating Plan(s) would result in the EOP-011 Operating Plan not being needed but if an Energy Emergency still occurs, the Operating Plans should have reduced the severity of the Energy Emergency.

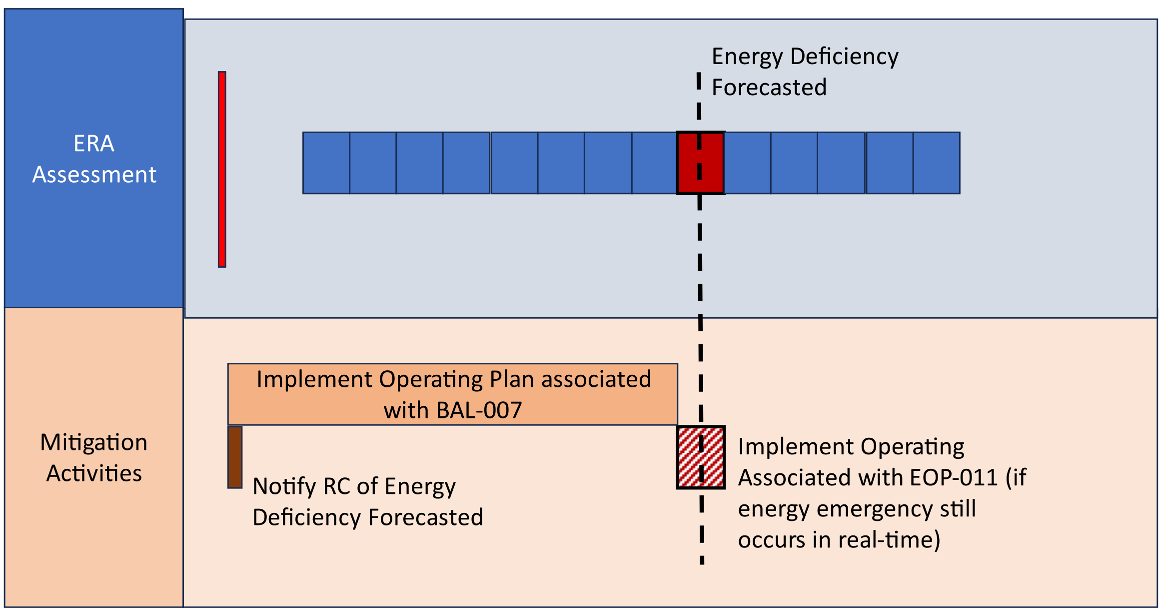

Figure 1. Timeline of ERA performance and Operating Plan Implementation if the forecasted energy deficiency is not fully mitigated when EOP-011 Operating Plan is still required.

Additionally, the BAL-007-1 assessments require considering energy risk which can only be performed by looking at an assessment over a time period with multiple time steps and considering the fuel supply and the production from just-in-time, variable energy resources. While EOP-011 Requirement R2 includes "Energy Emergencies" as a risk that Operating Plans must address, these assessments have generally been performed as capacity assessments, or potentially a series of capacity assessments in succession, which do not necessarily include variable energy and fuel risk, especially over a longer period of time. BAL-007-1 explicitly requires including these elements in an assessment and set criteria regarding when risks need to be addressed through Operating Plans.

The Balancing Authority (BA) may require additional data from other entities and should consider this when documenting the process. While BAL-007-1 does not require other entities to provide necessary data, TOP-003 requires the BA to "maintain a documented specification for the data necessary for it to perform its analysis functions…" in Requirement R2 and requires the other entities to provide the data in Requirement R5. To provide further clarity in TOP-003, "Near-term Energy Reliability Assessments" has been added to the list of activities for which the Balancing Authorities maintain and distribute a data specification for which applicable entities are required to provide.

Proposed New Terms:

Energy Reliability Assessment (ERA) – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

Rationale

The ERA definition was added to allow for Energy Reliability Assessments to be performed in different time horizons using similar processes prescribed by NERC standards, but also through other processes while maintaining a consistent understanding of what an ERA is. These assessments are intended to look at the wide variety of resources available to serve load's energy requirements not only in the near-term but also in other time horizons including the long-term planning horizon. ERAs go beyond the existing scope of the capacity assessments that have traditionally been performed to look more closely at energy needs.

The definition for Near-Term Energy Reliability Assessment provides further details for this specific type of ERA. Within the definition are requirements for the duration of a Near-Term ERA. It is the intent that Near-Term ERAs are performed on a routine basis and look at the time period that covers the next several days to weeks, and that all time periods will be effectively covered by some iteration of a Near-Term ERA. Assessments would be repeated as no later than when one expires to extend the outlook for the BA performing the ERA. To that end, in the interest of maintaining relevancy of the ERA, a five-day to six-week limit is placed on the duration. While six weeks is a long period of time, it gives regions the flexibility to assess the energy landscape over a period of time that encompasses the energy risks that they deem to be pertinent. It is expected that most Balancing Authorities will update their Near-Term ERAs on a more frequent basis, but the baseline requirement is flexible to allow for longer periods. The minimum duration of five days gives the Balancing Authority the foresight to evaluate fuel constraints and weather anomalies. Fuel constraints, specifically natural gas scheduling timelines, typically extend through a single day (e.g., today for tomorrow) during the week, and three-day strips over weekends. Holidays introduce a longer strip than the typical weekends. Five-day strips are traded at least once per year and sometimes more than once depending on where holidays fall on the calendar. That construct is one example of the factors that set the minimum of five days for Near-Term ERAs. Weather dependent resources, where prevalent, would drive the consideration for longer-duration assessments. Doldrums in wind and solar production will have a historical expectation for how long they typically last and should be considered with determining the minimum duration of the Near-Term ERA. Finally, there is a requirement that the initialization data being used to perform a Near-Term ERA be current. This is spelled out as "an assessment period that begins no later than two days after the operating day", the operating day being the day on which the ERA is being performed, or started, or completed. One interpretation that meets this requirement is that the first day of the Near-Term ERA is the current day, which is no later than two days out and provides good initialization of the models being used to perform the assessment. What this is intended to prevent is performing all

Near-Term ERAs in a single assessment at the start of a year or season, maintaining current, relevant, and useful information for the BA to make sound decisions.

Requirements:

Requirement R1

Requirement R1 identifies the basis for defining what a Near-Term ERA is. Basic input assumptions are specifically designed by each BA according to their risks and their supply resource mix and demand profiles. Because of differences in risks and in resource mixes and demand profiles between regions, rather than requiring a set of prescriptive elements to assess, each BA is provided with minimum assessment requirements which they will use to define their scope for performing their ERAs and document a rationale.

Balancing Authorities may perform the required ERAs for just their area or a group of BAs may jointly perform their ERAs. This is consistent with existing partnerships (e.g., Reserve Sharing Groups or resource adequacy collaboratives) between BAs that are used for other operations or planning activities and real time operations, and should be reflected in Near-Term ERAs and their associated Operating Plan(s). Should a deficiency be identified, the BAs, regardless of whether they performed their assessment jointly or individually, are expected to utilize all of their available resources, including those in other BA areas. The goal of the ERA is to determine if sufficient energy is available to meet demand at all times.

Demand profiles will be determined by the BA as well. Entities will have a number of items to consider prior to determining their Demand profile. It is up to the BA to determine exactly how Demand will be modeled, including considerations of how demand response is treated. A BA may choose to include market based or dispatchable demand response, but it is recommended that other forms of demand response should not be included, which would leave load reduction options as a last resort (e.g., voltage reduction, load cycling, etc.). Each BA will need to identify what their type of demand response is and when, if ever, to consider it. Load shed should only be identified as part of a plan if this is the last resort.

The heart of an ERA is the modeling of resource capabilities and their fuel supplies. This modeling includes constrained fuel supplies such as natural gas, inventoried fuels such as oil, coal, liquefied natural gas and some hydro, and just-in-time fuels like wind, solar, and run-of-river hydro. ERAs look at the production from generating resources over a period of time, which will impact their operation. Constrained fuels will deplete, limiting the operation of generation (i.e., fuel). All of these considerations go into modeling resource capabilities and operational limitations, including fuel supply.

Energy transfers with other Balancing Authorities is required to be modeled as well. This modeling is simply the interchange between areas that BAs count on in their day-to-day operation of their systems. It is recommended that BAs coordinate these assumptions to ensure consistencies on the common interface, but may not be required depending on the scope of the ERA as it is defined.

Finally, known Bulk Electric System (BES) Transmission constraints, that limit the ability of generation to deliver their output to load, are required to be included in the Near-Term ERA. This requirement was carefully worded such that a power flow or load flow analysis is NOT required to be performed, however

when a system has a known constraint that causes area generation to always be limited under certain specific conditions, and those conditions are expected to occur, then that generation should be reduced in the ERA as well.

ERAs should ensure that every period of time is evaluated, and document the frequency and duration that meets that intent. For example, performing a two-week long ERA every two weeks would meet the requirement. The determination of how long to study will be based on several factors such as system or generation outage recall timing, accuracy of forecast information beyond the next few days, or lead time for fuel replenishment. Each Balancing Authority will conduct a Near-Term ERA for all time periods unless the BA demonstrates that a Near-Term ERA is not necessary. This can be accomplished via screening tools that evaluate all of the factors above for risk and show that risk is low for that period of time. This requires documentation of the methods used to make that determination as well as the evaluation of the factors considered.

Requirement R2

Requirement R2 outlines a minimum set of Scenarios that must be included in a Near-Term ERA. The intent is to provide a mechanism for each BA to gauge whether or not they are close to an Energy Emergency. Credibility of the Scenarios is for the BA to define and document. The selected Scenarios are intended to stress the system, but may fall short of causing an Energy Emergency on their own. For example, raising demand during light load periods may not result in stressed system conditions, but would meet the intent of stressing the system. The BA is in full control of determining what Scenarios are appropriate.

There are four types of Scenarios, two for supply, one for Demand, and a combination of the two based on historically observed conditions that could occur again. Each of the Scenarios can be varied independently or in combination with each other. At least one parameter should be varied enough to stress the system to determine if the (remaining) available resources are robust enough to meet the Demand and Operating Reserves. A possible Scenario for Demand profiles could be raising Demand from a 50/50 profile to a higher profile, such as a 90/10 or maximum load Scenario, to measure the impact to the system and determine if energy shortfalls are forecasted. There are two supply side Scenarios to be included in the ERA. The first is an energy supply contingency that effectively removes energy resources from the base case and runs it again. Large energy resources may be the same as large capacity resources, but not necessarily in all cases. Typically, the results of the base Scenario will show the analyst what the largest source of energy is, which would be removed from the energy supply contingency Scenario. The second supply Scenario removes a set of resources that are supplied by the same fuel supply. This is traditionally thought of as natural gas supplying multiple generating stations and may be just that, but could also be a set of wind turbines that are closely situated, where a storm or lull could render them unavailable or with a very low production for a period of time. It could also include the loss of energy from solar panels that are covered by snow or smoke from a fire. The final Scenario is more versatile and can be tailored by the BA based on actual events that happened and could happen again within the horizon being assessed. This Scenario should be specific to the region, the time of year, the forecasted conditions, and any other expected conditions that the BA includes in the Near-Term ERA. For example, modeling a snow storm that covers solar panels during the winter months in a location where snow is prevalent makes sense but modeling the same storm during the

summer is unreasonable and is not expected to be done. It is possible that this Scenario is simply documented that there are no historical events that fit the current forecasted conditions, or that the Scenario is the same as those described in R2.1.1 through 2.1.3. When this occurs, the Balancing Authority should include that description in their process.

Regardless of the chosen energy and fuel Scenarios, it is up to the BA to determine which resource or set of resources are included in the ERA. The choices by the BA in Scenarios must be identified and documented.

Requirement R3

The time horizon specified in the Near-Term ERA definition offers a different vantage point than next day and real-time capacity assessments. The actions that a BA can take due to an identified risk of an energy shortfall are different when identified days to weeks earlier than if waiting for a next day or real-time capacity assessment. They are also different when comparing the energy aspect of the ERA to a capacity assessment. An example of actions that could be taken based on the results of a Near-Term ERA that may not be available for a next day or real-time assessment include requesting for energy resources or transmission facilities to return from maintenance or construction outages earlier than planned or to postpone a planned outage. Additional actions that could be considered for an energy shortfall that would be overlooked in a capacity assessment is the conservation of stored fuel or the optimization of energy storage (e.g., pumped storage hydro or batteries). If an entity were to wait for the next day studies to identify a risk, fewer options for the BA to avoid an energy risk in real time would be available.

Provisions for communication with the Reliability Coordinator is simply a documented process including the forecasted conditions when the RC will be alerted to the results of the Near-Term ERA and/or the implementation of Operating Plans. Many of the actions that are included in Operating Plans will not require communication of any kind (e.g., waiting for better forecasts), but some may require that communication (e.g., recall of transmission facilities). The procedure used to document the performance of Near-Term ERAs including a section that clearly defines what communications are required by the BA meets this requirement.

Requirement R3 requires BAs to develop Operating Plans prior to forecasting Energy Emergencies through ERAs to minimize their effects. These Operating Plans are developed so that in the event that an ERA shows that a BA may have insufficient energy, they will have an Operating Plan ready to implement, per Requirement R3, that has been developed and communicated before system conditions are unfavorable and be ready for later implementation. Operating Plans are expected to include actions that can be performed by the BA within the time horizon for which the ERA is designed, near-term. The actions that BAs may include in Operating Plans will also provide information to the BA regarding how long the assessment period of the ERA might need to be (Requirement R1) such that they can have time to accomplish the actions identified. For example, if actions that could minimize potential Energy Emergencies take two weeks to accomplish, the ERA should be looking at least two to three weeks into the future.

As discussed in the Relationship to other Standards section, the Operating Plans developed based on this requirement are not intended to supersede Operating Plans associated with TOP and EOP standards but to

complement them and include actions that could reduce the likelihood or severity of an energy deficiency occurring in real-time. To that end, the BA develops an appropriate Operating Plan for a forecasted Energy Emergency that is identified by an ERA. Depending if the ERA is completed weeks or days prior to the forecasted Energy Emergency, the BA decides on suitable plans to reduce the impact. Since the Operating Plans are being implemented based on assessments looking days to weeks ahead, considering the associated uncertainty of the results, BAs may decide to exclude actions in the BAL-007-1 Operating Plans which would only need to occur much closer to the projected event or only plan to implement those actions if the projected conditions of the ERA appear that they will still occur. For example, an Operating Plan may include increasing the frequency of performing ERAs in order to monitor whether the forecasted Energy Emergency is more or less likely as the uncertainty of input data to the assessment decreases and other actions in the Operating Plan have been implemented. Again, the goal of performing an ERA is to identify those times when a forecasted Energy Emergency might occur. The developed Operating Plan should have steps that can be taken to reduce, or mitigate, the forecasted Energy Emergency.

The ERA Operating Plans should be designed to be adaptable to unfolding conditions and proactive enough to possibly avoid an energy shortage through advanced actions. As an example, to illustrate the Operating Plan uses, when an ERA is performed two weeks ahead of a calculated shortfall then potential actions have a two-week timeline to perform the appropriate action plans as well as monitor if the identified risk conditions have changed. For instance, if the results from a two-week duration ERA during an extremely cold period determines an Energy Emergency may occur, the BA's Operating Plan could include the following actions:

- Survey scheduled outage system to determine if any generation currently out for maintenance can return earlier than planned.
- Survey if any transmission outages affect either generation deliverability or import capability. If yes, can they be returned to service prior to the forecasted Energy Emergency.
- Survey if generation and transmission scheduled to go out can defer their outages until after the event.
- Communication with Reliability Coordinator and other relevant entities of the projected risk (e.g., government authorities for assessing the need and strategy for public appeals for conservation, or other BAs to account for expected imports or exports and potentially facilitate higher transfers).
- Ensure all energy storage units can be fully available to help mitigate energy shortfalls.
- Increase frequency of performance of ERAs, including possibly daily, and assess energy availability and have Operating Plan actions conditional on the level of risk.
- If ERA results still indicate unacceptable risk of energy deficiency two days prior to projected event, instruct thermal plants to warm up leading up to event to avoid outages due to ice formation and cold-start issues.

Ideally, these actions will reduce or prevent an Energy Emergency that might occur in real-time. However, if the Energy Emergency still occurs, these actions should reduce the energy deficiency and prepare the BAs

to implement an emergency Operating Plan. This scenario is intended only to be one simple illustrative example that does not reflect all potential Operating Plan actions or actions that BAs in all regions can do.

While scheduling increased imports can be a part of the Operating Plan, it is imperative that the BA verify that the resources they have scheduled will continue to be there to solve their Energy Emergency. It should not be assumed that once imports are scheduled, this energy is a firm supply. Both BAs may be impacted by the event causing an Energy Emergency for both areas. The supplying entity may not be able to honor their agreement to provide this energy.

Requirement R4

Requirement R4 specifies that the near-term ERA be performed as designed.

Requirement R5

Requirement R5 specifies what constitutes two circumstances that identify a forecasted Energy Emergency. The forecasted Energy Emergency conditions are intended to be a clear threshold where the ERA results identify levels of impending risk and require actions be performed to minimize the potential they will occur. The definitions of what constitutes a forecasted Energy Emergency are in alignment with the Energy Emergency Alert (EEA) definitions in EOP-011. The difference for BAL-007-1 is that instead of being a real-time Energy Emergency, these would be forecasted events. The goal here is that if an Energy Emergency is forecasted in an ERA, the associated Operating Plan will have targeted steps to help minimize the forecasted Energy Emergency before it gets to be an Energy Emergency in the next day and real-time timeframes.

There are three EEA levels, two of which are associated with forecasted Energy Emergencies. The criteria for forecasted Energy Emergency apply also to Scenarios identified in Requirement 2. This level of granularity allows for the BA to design an Operating Plan that fits the specific situation. Some Scenarios may be expected to enter the lower levels of an Energy Emergency, and the actions in an Operating Plan should be appropriate for that combination.

Finally, by leveraging the existing terms used in EOP-011 for EEA, clear and well-understood definitions are already in place which require little to no training, beyond the advanced timing associated with BAL-007-1. BAs have existing interpretations of how they respond when nearing or entering an EEA and the existing interpretations are expected to be used, including those that involve interaction with Reserve Sharing Groups.

Requirement R6

Requirement R6 requires that the BA review their process, Scenarios, and Operating Plans, in Requirements R1 through R3, to determine if any changes are needed. The BA shall review this documentation at least once every 24 months. Due diligence during the design and review phases by the BA is required to identify potential risks and possible actions that could minimize those risks that would lead to an energy shortfall in the near-term timeframe.

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Exhibit E

Analysis of Violation Risk Factors and Violation Severity Levels

Violation Risk Factor and Violation Severity Level Justifications

Project 2022-03 Energy Assurance with Energy-Constrained Resources

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2022-03 Energy Assurance with Energy-Constrained Resources. 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 DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

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

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

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a “binary” type requirement must be a “Severe” VSL.
Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

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

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

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

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

VRF Justifications for BAL-007-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the process for conducting Energy Reliability Assessments for the near-term time horizon which are required in defining the minimum standards by which Energy Reliability Assessments will be performed 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 BAL-007-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 or Part 1.2.	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 through Part 1.2. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for one of the elements in Requirement R1 Part 1.3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.

VSL Justifications for BAL-007-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for BAL-007-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining a set of scenarios or a method of Scenario creation which are required in defining the minimum standards by which near-term Energy Reliability Assessments will be performed 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 BAL-007-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include one of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include two of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include three of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include any of the conditions listed in Requirement R2 Part 2.1. OR The Balancing Authority failed to document a set of Scenarios or a method of developing Scenarios for use in performing Near-Term ERAs.

VSL Justifications for BAL-007-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not 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 BAL-007-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term Energy Reliability Assessment, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s) 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 BAL-007-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority documented an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs.

VSL Justifications for BAL-007-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that near-term Energy Reliability Assessments were not performed according to the process documented in Requirement R1 using the scenarios or methods documented in Requirement R2 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 BAL-007-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to perform a Near-Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.

VSL Justifications for BAL-007-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that if an Operating Plan(s) was not implemented once a near-term Energy Reliability Assessment identified one or more forecasted Energy Emergencies it 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 BAL-007-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a Near-Term ERA identified any of the forecasted conditions in Requirement R5.

VSL Justifications for BAL-007-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R6	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of low is appropriate due to the administrative nature of the Balancing Authority providing the Reliability Coordinator with its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3.
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 low 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 low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-007-1, Requirement R6

Lower	Moderate	High	Severe
N/A	N/A	The Balancing Authority reviewed information that contained the Near-Term ERAs process, the Scenarios or methods, and Operating Plan(s) but failed to update within 24 months.	The Balancing Authority failed to review, update, and provide the Near-Term ERAs process, the Scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.

VSL Justifications for BAL-007-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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-003-6

VRF Justification for TOP-003-7, Requirement R2

The VRF did not change from the previously FERC approved TOP-003-6 Reliability Standard. The modifications made to R2 are similar in content to the previous draft and therefore the VRF remained low.

VSL Justification for TOP-003-7, Requirement R2

Please refer to the VSL table located below.

VRF Justification for TOP-003-7, Requirement R4

The VRF did not change from the previously FERC approved TOP-003-6 Reliability Standard. The modifications made to R4 are similar in content to the previous draft and therefore the VRF remained low.

VSL Justification for TOP-003-7, Requirement R4

Please refer to the VSL table located below.

VSLs for TOP-003-7, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not

			have a documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-7, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional assessment to Requirement R2. The proposed VSL was modified to reflect the additional assessment. It does not have unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, therefore, consistent with the requirement.

VSL Justifications for TOP-003-7, Requirement R2	
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.

VSLs for TOP-003-7, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to three entities, or more than10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-7, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional assessment to Requirement R4. The proposed VSL was modified to reflect the additional assessment. It does not have unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1 and TOP-003-7.

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 2022-03 SDT members is included in **Exhibit G**.

II. Standard Development History

A. Project Initiation

In 2022, the Reliability and Security Technical Committee ("RSTC") formed the Energy Reliability Assessment Task Force ("ERATF") to assess risks associated with energy- constrained resources. Project 2022-03 addresses recommendations from the NERC ERATF to create or modify NERC Reliability Standards across the operations/operational planning time horizon and the long-term planning time horizon.

B. Standard Authorization Request Development

On June 15, 2022, the Standards Committee accepted two ERATF Standard Authorization Requests ("SARs") to address Energy Assurance with Energy-Constrained Resources and authorized posting the SARs for a 30-day informal comment period and the solicitation of SAR

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

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

drafting team members.[3] The informal comment period and the nomination period for a SAR drafting team was open from June 22, 2022 through July 21, 2022.[4]

C. Acceptance of Revised ERATF SARs

On January 25, 2023, the Standards Committee accepted the revised SARs, authorized drafting revisions to the Reliability Standards identified in the SARs, and appointed the Project 2022-03 SAR drafting team as the Project 2022-03 Standard Drafting Team.[5]

D. Informal Comment Period

The Standard Drafting Team conducted an informal comment period from September 13, 2023 through October 5, 2023 to collect feedback on proposed new definitions and new TOP-0XX Standard language.[6]

E. First Posting – Comment Period, Initial Ballot, and Non-binding Poll, BAL-007-1

On January 17, 2024, the Standards Committee authorized initial posting of proposed Reliability Standard BAL-007-1, the associated Implementation Plan and other associated documents for a 45-day formal comment period from January 25, 2024 through March 11, 2024, with a parallel initial ballot and non-binding poll on the Violation Risk Factors ("VSFs") and Violation Severity Levels ("VSLs") held during the last 10 days of the comment period from March 1, 2024 through March 11, 2024.[7] The initial ballot for Proposed Reliability Standard BAL-007-1 received 6.08 percent approval, reaching quorum at 89.81 percent of the ballot pool, and the

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3 NERC, *Meeting Minutes – Standards Committee Meeting* (June 15, 2022), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20June%20Meeting%20Minutes%20-%20Approved%20July%2020,,%202022.pdf.

4 *See* Exhibit F, Complete Record of Development, at items 5, 9.

5 NERC, *Meeting Minutes – Standards Committee Meeting* (Jan. 25, 2023), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/January%20Meeting%20Minutes%20-%20Approved%20February%2022,%202023.pdf.

6 *See* Exhibit F, Complete Record of Development at items 15, 16.

7 *Id.* at items 23, 26.

additional ballot for the associated Implementation Plan received 11.58 percent approval reaching quorum at 89.49.[8] The non-binding poll for the associated VRFs and VSLs received 5.49 percent supportive opinions, reaching quorum at 86.59 percent of the ballot pool.[9] There were 57 sets of responses, including comments from approximately 186 different individuals and approximately 109 companies, representing 10 industry segments.[10]

F. Comment Period, Ballot, and Non-binding Poll, BAL-008-1; BAL-007-1

The first draft of proposed Reliability Standard BAL-008-1 and the second draft of BAL-007-1, along with the associated Implementation Plan, and other associated documents were posted for an extended 49-day formal comment period from May 7, 2024 through June 24, 2024, with a parallel additional ballot and non-binding poll held from June 11, 2024 through June 24, 2024.[11]

- Proposed Reliability Standard BAL-008-1 received 16.84 percent approval, reaching quorum at 79.3 percent of the ballot pool, and the additional ballot for the associated Implementation Plan received 15.51 percent approval with 78.5 percent quorum.[12] The non-binding poll for the associated VRFs and VSLs received 9.21 percent supportive opinions, reaching quorum at 75.84 percent of the ballot pool.[13]
- Proposed Reliability Standard BAL-007-1 received 17.19 percent approval, reaching quorum at 81.89 percent of the ballot pool, and the additional ballot for the associated Implementation Plan received 19.04 percent approval with 81.71

8 *Id.* at items 28, 29.
9 *Id.* at item 30.
10 *Id.* at item 24.
11 *Id.* at item 41.
12 *Id.* at items 48, 49.
13 *Id.* at item 50.

percent quorum.[14] The non-binding poll for the associated VRFs and VSLs received 10.37 percent supportive opinions, reaching quorum at 79.27 percent of the ballot pool.[15]

There were 64 sets of responses, including comments from approximately 161 different individuals and approximately 99 companies, representing 10 industry segments.[16]

G. First Posting – Comment Period, Initial Ballot, and Non-binding Poll, TOP-003-7

On September 18, 2024, the Standards Committee authorized initial posting of proposed Reliability Standard TOP-003-7, the associated Implementation Plan and other associated documents for a 47-day formal comment period from September 19, 2024 through November 4, 2024, with a parallel initial ballot and non-binding poll on the Violation Risk Factors ("VSFs") and Violation Severity Levels ("VSLs") held during the last 10 days of the comment period from October 25, 2024 through November 4, 2024.[17] The initial ballot for Proposed Reliability Standard TOP-003-7 received 92.77 percent approval, reaching quorum at 85.38 percent of the ballot pool, and the additional ballot for the associated Implementation Plan received 76.3 percent approval reaching quorum at 85.83.[18] The non-binding poll for the associated VRFs and VSLs received 86.09 percent supportive opinions, reaching quorum at 84.36 percent of the ballot pool.[19] There were 54 sets of responses, including comments from approximately 167 different individuals and approximately 103 companies, representing 10 industry segments.[20]

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14 *Id.* at items 51, 52.

15 *Id.* at item 53.

16 *Id.* at item 43.

17 NERC, *Meeting Minutes – Standards Committee Meeting* (Sept. 18, 2024), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/September_Meeting_Minutes_2024.pdf.

18 *See* Exhibit F, Complete Record of Development at items 68, 69.

19 *Id.* at item 70.

20 *Id.* at item 64.

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

Proposed Reliability Standard BAL-007-1, the associated Implementation Plan and other associated documents were posted for a 47-day formal comment period from September 19, 2024 through November 4, 2024, with a parallel additional ballot and non-binding poll held during the last 10 days of the comment period from October 25, 2024 through November 4, 2024.[21] Proposed Reliability Standard BAL-007-1 received 81.53 percent approval, reaching quorum at 87.92 percent of the ballot pool, and the additional ballot for the associated Implementation Plan received 83.72 percent approval reaching quorum at 88.33.[22] The non-binding poll for the associated VRFs and VSLs received 79.61 percent supportive opinions, reaching quorum at 85.77 percent of the ballot pool.[23] There were 54 sets of responses, including comments from approximately 167 different individuals and approximately 103 companies, representing 10 industry segments.[24]

I. Final Ballot

Proposed Reliability Standards TOP-003-7 and BAL-007-1 were posted for a 10-day final ballot period from November 25, 2024 through December 4, 2024. The ballot for the proposed Reliability Standards and associated documents are as follows:

- Proposed Reliability Standard TOP-003-7 reached quorum at 86.92 percent of the ballot pool, receiving support from 93.25 percent of the voters. The ballot for the Implementation Plan reached quorum at 87.01 percent of the ballot pool, receiving support from 85.56 percent of the voters.[25]

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21 *Id.* at items 63, 66.

22 *Id.* at items 71, 72.

23 *Id.* at item 73.

24 *Id.* at item 64.

25 *Id.* at items 85, 86.

- Proposed Reliability Standard BAL-007-1 reached quorum at 88.68 percent of the ballot pool, receiving support from 81.31 percent of the voters. The ballot for the Implementation Plan reached quorum at 89.11 percent of the ballot pool, receiving support from 86.76 percent of the voters.[26]

J. Board of Trustees Adoption

The NERC Board of Trustees adopted proposed Reliability Standards TOP-003-7 and BAL-007-1 on December 10, 2024.[27]

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[26] *Id.* at items 87, 88.

[27] NERC, *Board of Trustees Agenda Package Feb., 2024*, Agenda Item 3d. (Project 2022-03 Energy Assurance with Energy-Constrained Resources), https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Board_Open_Meeting%20Agenda%20Package%20-%20December%202024%20-%20ATT.pdf.

Complete Record of Development

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Related Files

Status

The final ballots for **BAL-007-1 Near-term Energy Reliability Assessments, TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection,** and their implementation plans concluded **8 p.m. Eastern, Wednesday, December 4, 2024.** The voting results can be accessed via the links below. The standards will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

Background

Project 2022-03 currently is addressing the operations/operational planning time horizon Standard Authorization Requests (SARs) that seek to enhance reliability by requiring entities to perform Energy Reliability Assessments (ERAs) to evaluate energy assurance and develop Corrective Action Plan(s), Operating Plan(s), or other mitigating actions to address identified risks to each respective time horizon.

The Standards Committee (SC) accepted the revised SAR at its January 25, 2023, meeting. At the same meeting, the SC authorized drafting of the Reliability Standard(s) identified in the SAR. Since that time, the team has conducted several meetings, both remote and in-person, and posted a draft of a new standard for informal comment to solicit feedback and completed one initial comment and ballot period for BAL-007-1.

Standard(s) Affected: TPL-001-5.1, EOP, TOP, and BAL

Purpose/Industry Need

This project will enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and develop Corrective Action Plan(s) to address identified risks. Energy reliability assessments evaluate energy assurance across the Operations Planning, Near-Term Transmission Planning, and Long-Term Transmission Planning or equivalent time horizons by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.

[1] Energy_Assurance_White_Paper (nerc.com)

Draft	Actions	Dates	Results	Consideration of Comments
Final Ballots **TOP-003-7** **(74)** Clean | **(75)** Redline to Last Posted **BAL-007-1** **(76)** Clean | **(77)** Redline to Last Posted **Implementation Plan** for BAL-007-1 and TOP-003-7 **(78)** Clean | **(79)**Redline to Last Posted **Supporting Materials** **Technical Rationale** **(80)** BAL-007-1 and TOP-003-7 **VRF/VSL Justifications** **(81)** BAL-007-1 and TOP-003-7 **Definitions** **(82)** Energy Reliablity Assessment **(83)** Near-Term Energy Reliablity Assessment	Final Ballots **(84)** Info Vote	11/25/24 - 12/04/24	Ballot Results **(85)** TOP-003-7 **(86)** Implementation Plan **(87)** BAL-007-1 **(88)** Implementation Plan	
Draft 1 TOP-003-7 **(54)** Clean | **(55)** Redline to Last Approved **Draft 3** BAL-007-1 **(56)** Clean | **(57)** Redline to Last Posted Implementation Plan for BAL-007-1 and TOP-003-7 **(58)** Clean | **(59)** Redline to Last Posted **Supporting Materials** **(60)** Unofficial Comment Form (Word) **Technical Rationale** **(61)** BAL-007-1 and TOP-003-7 **VRF/VSL Justifications** **(62)** BAL-007-1 and TOP-003-7	Initial Ballots and Non-binding Poll TOP-003-7 Additional Ballots and Non-binding Poll BAL-007-1 **(66)** Ballot Open Reminder **(67)** Info Vote	10/25/24 - 11/04/24	Ballot Results **(68)** TOP-003-7 **(69)** Implementation Plan **(70)** Non-binding Poll Results **(71)** BAL-007-1 **(72)** Implementation Plan **(73)** Non-binding Poll Results	**(65)** Consideration of Comments
	Join Ballot Pools for TOP-003-7	09/19/24 - 10/18/24		
	Comment Period **(63)** Info Submit Comments	09/19/24 - 11/04/24	**(64)** Comments Received	
Draft 1 **(31)** BAL-008-1 **(32)** Implementation Plan **Draft 2** BAL-007-1 **(33)** Clean | **(34)** Redline to Last Posted **(35)** Implementation Plan	Initial Ballots and Non-binding Poll BAL-008-1 Additional Ballots and Non-binding Poll BAL-007-1 **(45)** Updated Info (Ballot Reminder) **(46)** Updated Info (Extension) **(47)** Info Vote	06/11/24 - 06/24/24 (extended to reach quorum)	Ballot Results **(48)** BAL-008-1 **(49)** Implementation Plan **(50)** Non-binding Poll Results **(51)** BAL-007-1 **(52)** Implementation Plan **(53)** Non-binding Poll Results	

Supporting Materials (36) Unofficial Comment Form (Word) **Technical Rationales** (37) BAL-007-1 (38) BAL-008-1 **VRF/VSL Justifications** (39 BAL-007-1 (40) BAL-008-1	Join Ballot Pools	05/07/24 - 06/05/24		(44) Consideration of Comments
	Comment Period (41) Updated Info (Extension) (42) Info Submit Comments	05/7/24 - 06/24/24 (extended)	(43) Comments Received	
Draft 1 (18) **BAL-007-1** (19) Implementation Plan **Supporting Materials** (20) Technical Rationale (21) Unofficial Comment Form (22) VRF/VSL Justifications	Initial Ballot (26) Ballot Open Reminder (27) Info Vote	03/01/2024 - 03/11/2024	Ballot Results (28) BAL-007-1 (29) Implementation Plan (30) Non-binding Poll Results	(25) Consideration of Comments
	Join Ballot Pools	01/25/2024 - 02/23/2024		
	Comment Period (23) Info Submit Comments	01/25/2024 - 03/11/2024	(24) Comments Received	
(14)**TOP-0XX-X** **Supporting Materials** (15) Unofficial Comment Form (Word)	Comment Period (16) Info Updated Submit Comments	09/13/2023 - 10/05/2023	(17) Comments Received	
Operations and Operations Planning Time Horizons SAR (10) Clean| (11) Redline **Planning Time Horizons SAR** (12) Clean | (13) Redline	The Standards Committee accepted these SARs on January 25, 2023			
Drafting Team Nominations **Supporting Materials** (8) Unofficial Nomination Form (Word)	Nomination Period (9) Info Submit Nominations	06/22/2022 – 07/21/2022		
(1) Operations and Operations Planning Time Horizons SAR (2) Planning Time Horizons SAR **Supporting Materials** (3) Unofficial Comment Form (Word) (4) ERATF Technical Justification	Comment Period (5) Info Submit Comments	06/22/2022 – 07/21/2022	(6) Comments Received	(7) Consideration of Comments

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

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:	Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons		
Date Submitted:	June 8, 2022		
SAR Requester			
Name:	Chair Peter Brandien on behalf of the Energy Reliability Assessment Task Force (ERATF)		
Organization:	The ERATF of the Reliability and Security Technical Committee (RSTC)		
Telephone:	(413) 535-4022	Email:	pbrandien@iso-ne.com
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?):			
Unassured deliverability of fuel supplies, coincident with inconsistent output from variable renewable energy resources and volatility in forecasted load, can result in insufficient amounts of energy available from the BES needed to serve electrical demand and ensure the reliable operation of the BES throughout each hour of the time period being evaluated.[1] Historically, analyses of energy available to the BES focused on capacity reserve levels across peak-demand time periods. Generating resources and the requisite fuel were assumed available. This was a logical assumption in the past as fuel availability was assured with either firm fuel contracts (commodity plus transportation capacity), or on-site storage (e.g., oil, coal, reservoir-based hydro), or required periodic and predictable fuel replacement (e.g., nuclear). The availability of dispatchable generation			

[1] The industry need is described in the *Ensuring Energy Adequacy with Energy-Constrained Resources* white paper, presented to the RSTC, December 2020.

Requested information
with diverse fuel types promoted flexibility in providing energy for the BES should one fuel type become unavailable. Today, the transition from coal and nuclear generation to wind, solar, natural gas (with and without oil back up), distributed energy resources, and hybrid (renewables plus energy storage) resources is creating a more complex scenario and highlighting the need for energy assurance. Installed generating capacity analysis alone is not sufficient to ensure a reliable supply of energy for the BES. The proliferation of intermittent renewable generation in the resource mix increases the importance of having precisely controllable resources with sufficient fuel available, ready to respond when needed. The increasing prevalence of distribution-level resources and flexible load programs introduces added volatility into energy forecasts, further complicating operations energy reliability assessments. Supply intermittency and demand volatility both require the dispatchable generating fleet to be available and flexible enough to respond when called upon. These factors can also lead to unexpected and unstudied energy issues in non-peak hours, a risk that would not be identified by traditional analyses focusing on capacity across the peak demand periods. The transition to more intermittent resources is increasing the reliance on natural gas as the fuel needed for dispatchable resources that can promote energy assurance; however, uncertainty is still an issue if the natural gas-fueled resources are subject to fuel curtailment or interruption (by virtue of fuel acquisition contracts) during peak fuel demands which often correspond with winter-peak electric demands. Additionally, the design of natural gas pipeline systems and the availability of back-up natural gas feeders can impact individual generators and the BES under pipeline disruption scenarios. The intermittency of renewable generation, demand volatility, the need for sufficient flexibility from balancing generation resources, and the potential for natural gas supply interruptions all combine to highlight the need for energy reliability assessments that analyze all hours of a given study period rather than just the peak hours. Energy assurance and fuel assurance risks are becoming more apparent as extreme weather has resulted in energy deficits (as opposed to capacity deficits) in recent years. During the past 10 years, there have been multiple extreme events have jeopardized the BES. In February 2011[2], an arctic cold front in the southwest United States resulted in generation outages and natural gas facility outages. In January 2014[3], a polar vortex affected the central and eastern United States and Texas. Another event in 2014 triggered generation outages and natural gas availability issues. In January 2018[4], the south central United States experienced many generation outages resulting in emergency measures. In 2021, the Oroville hydroelectric facility was shut down when reservoir levels, due to drought conditions, dropped below its minimum operating elevation. Finally, the cold weather

[2] Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - FERC and NERC
[3] Polar Vortex Review
[4] 2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018

Requested information
event of February 2021[5] impacted Mississippi, Louisiana, Arkansas, Oklahoma, and Texas. Events like these highlight the need for a new approach to reliability operations that considers the extreme conditions and variability that the BES is increasingly experiencing. As part of ongoing operations planning, many entities have started incorporating some limited energy reliability assessments (e.g., uncertainty around renewable output) into reliability studies that produce key metrics; however, there is inconsistency among entities in whether and how the assessments are performed. To achieve the level of consistency needed across the industry, energy reliability assessments for the operations (< one year) time horizon and the mitigation of identified risks must be mandated and codified in NERC Reliability Standard requirements.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This project will enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and develop Corrective Action Plan(s) to address identified risks. Energy reliability assessments evaluate energy assurance across the operations time horizons[6] by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.
Project Scope (Define the parameters of the proposed project):

The project scope is to create or modify NERC Reliability Standards to address the following:
• Create requirement(s) to accomplish the following:
  ▪ Create defined terms (e.g., energy reliability assessment, energy assurance, extreme event analysis) as needed (refer to Appendix B for proposed definitions to key terms).
  ▪ Conduct an energy reliability assessment:
    ○ Define a period of time to be studied that appropriately considers the specific characteristics of the resources in the area being evaluated, including such properties as the logistics involved in the replenishment of fuel and the ability to accurately forecast or assume system conditions. Time periods are expected to differ between areas due to the notable differences in electric systems, interconnected fuel delivery systems, weather, climate, operating philosophies, and other contributing factors.
    ○ Account for uncertainty related to both supply and demand across all hours of a studied period. Potential sources of uncertainty to be considered include but are not limited to:
      - Time-coupled restrictions on the availability of fuel, including the limited capability to replenish fuel at or above the rate at which it is consumed. This includes transportation of stored fuels, such as oil and coal, as well as the delivery of fuels with continuous

[5] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - FERC, NERC and Regional Entity Joint Staff Inquiry
[6] The phrases "Operations Planning" and "Same-day Operations" are not NERC glossary terms but are referenced in the NERC document: https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

Requested information
delivery, such as natural gas. Where relevant, incorporate potential contractual limitations on fuel availability. * Outage duration informed by potential failure modes. * Flexibility/operational constraints of resources. * Disruptions to fuel delivery supply chains (e.g., pipeline outages, constraints on natural gas availability due to extreme cold). * Coincident outages of multiple independent resources. * Common mode outages not connected to fuel supply. * Variability of potential renewable profiles/availability. * Impact of energy storage resources. * Transmission capacity and deliverability to the load centers, including imports. * Correlated impact of weather and other significant events on load and generation[7]. * Extreme weather. • Energy reliability assessments should be required to: ▪ Include an evaluation of the unique characteristics of variable resources and their impact(s) on non-variable resources. ▪ Be coordinated between areas to synchronize interchange assumptions. ▪ Be conducted on a clearly defined periodic basis and performed in each of the NERC defined[8] operations time horizons. ▪ Be periodically validated and updated, and updated when changes to assumptions and input data nullifies an existing assessment. • For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Instead, each entity will establish and document criteria as part of complying with the Standard. • When predefined criteria are not met, require development of Corrective Action Plans. • Coordinate with the drafting team that is working on the "Energy Assessments with Energy–Constrained Resources in the Planning Time Horizons" SAR. • Coordinate with the NERC Electric-Gas Working Group, the North American Energy Standards Board, and the *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and*

[7] For example, cascading series of issues (including an extreme cold weather event across a significant portion of the NERC footprint), multiple forced outages early in the morning (when there is a lack of solar resources), and inadequate availability of natural gas. A wide area impact makes depending on imports less available.

[8] https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

Requested information
Coordination drafting team to minimize duplication of efforts and ensure that non-conflicting requirements are developed.
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[9] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The basis for this SAR was first identified in the NERC white paper entitled *Ensuring Energy Adequacy with Energy-Constrained Resources,*[10] which suggested several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Based on eleven questions formulated in the whitepaper, the NERC ERATF developed and distributed a survey questionnaire to subgroups of the Reliability and Security Technical Committee and Independent System Operators/Regional Transmission Organizations. The purpose was to refine the understanding of the issues identified in the whitepaper and gather feedback on energy assurance for three focus areas: • Energy assurance and flexibility for the evolving resource mix • Natural gas delivery assurance • Metrics, procedures, and analysis The goal of the survey was for the ERATF members to better understand how stakeholders are evaluating their energy constraint and fuel availability issues. The survey was based on the original eleven questions from the whitepaper and tailored to obtain more specific answers. For example, sub-questions were added to understand how specific assessment input assumptions were developed and how the impact of varying those assumptions was assessed. These responses provided a large amount of information to help evaluate the energy constraint issues. Summaries of the responses were presented to the ERATF in October 2021. Generally, the responses indicated the industry understands the purpose of energy analyses and performs energy studies. It was evident that energy issues vary from one area to another, and there are a multitude of variables to consider in terms of energy-related risks. The responses also pointed out that energy analysis is an imperative as the grid moves away from the traditional generation fleet to a resource mix that is weather dependent and energy constrained. In February 2021, the ERATF conducted a workshop to showcase the types of energy analyses already being performed in both the operations and planning time horizons, as well as the tools being developed to support such studies. A key takeaway was that energy analyses are crucial, achievable, and essential. The inter-regional impact of energy-related risks requires that a consistent base method

[9] 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.
[10] Energy_Assurance_White_Paper (nerc.com)

Requested information
and metrics for studies be developed and employed to continue the reliable operation of the BES and providing essential reliability services. Refer to the ERATF Technical Justification document (Appendix A) for additional information.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
It is not the ERATF's intention to require specific solutions to the energy-related issues identified in the assessments. This SAR is intended to propose modifications to NERC Reliability Standards to require that responsible entities further evaluate risks related to energy availability. In addition, the SAR proposes revisions to Reliability Standards that would require responsible entities to create Corrective Action Plans to address risks related to energy availability. Using a performance-based approach would allow entities to take local, state, and regional needs, as well as federal regulations and other factors as appropriate into consideration. The costs associated with this assessment are expected to be comparable to those associated with the responsible entity's activities to evaluate and address potential reliability risks to the System. The cost impact is unknown and will be considered during drafting team meetings.
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 characteristics of the BES facilities impacted by this project include: fuel type, delivery logistics (e.g., the ability to access additional fuel, sufficient road and rail networks, barges for waterway-based plants, liquefied natural gas deliveries), design, construction, and operational characteristics, etc.
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):
Primary: Reliability Coordinator and Balancing Authority. Impacted: Distribution Provider, Transmission Operator, Transmission Owner, Generator Operator, and Generator Owner
Do you know of any consensus building activities[11] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The ERATF's SAR development process is a consensus building activity and includes input from its members and observers. Previous drafts of the SAR have been presented to and commented on by the Reliability and Security Technical Committee and the Member Representatives Committee members. Those comments are incorporated into the updated SAR. On February 16, 2022, the ERATF conducted an industry workshop that outlined the challenges and considerations concerning solutions for performing energy reliability assessments. On May 19, 2022, the ERATF conducted a follow-up industry webinar to provide an update on how the SAR comments were addressed.

[11] 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
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)?
Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination: consider the impact to the TPL, EOP, and TOP standards
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.
Three reliability guidelines have been published in recent years that provide valuable tools for industry to assess and manage energy risks, particularly risks related to fuel assurance. However, the continued reoccurrence of extreme events and resulting impacts on fuel and energy supplies have demonstrated that Reliability Standard(s) are needed to provide consistency across the industry in performing energy reliability assessments and mitigating identified reliability risks. Reliability and Security Guidelines (nerc.com) • Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis • Reliability Guideline: Generating Unit Winter Weather Readiness • Reliability Guideline: Gas and Electrical Operational Coordination Considerations

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
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	

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon		
Date Submitted:	June 8, 2022		
SAR Requester			
Name:	Chair Peter Brandien on behalf of the Energy Reliability Assessment Task Force (ERATF)		
Organization:	The ERATF of the Reliability and Security Technical Committee (RSTC)		
Telephone:	(413) 535-4022	Email:	pbrandien@iso-ne.com
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?):			
Unassured deliverability of fuel supplies, coincident with inconsistent output from variable renewable energy resources and volatility in forecasted load, can result in insufficient amounts of energy available from the BES to serve electrical demand and ensure the reliable operation of the BES throughout each hour of the time period being evaluated[1]. Historically, analyses of energy available to the BES focused on capacity reserve levels across peak-demand time periods. Generating resources and the requisite fuel were assumed available. This was a logical assumption in the past as fuel availability was assured with either firm fuel contracts (commodity plus transportation capacity), or on-site storage (e.g., oil, coal, reservoir-based hydro), or required periodic and predictable fuel replacement (e.g., nuclear). The availability of dispatchable generation			

[1] The industry need is described in the *Ensuring Energy Adequacy with Energy-Constrained Resources* white paper, presented to the RSTC, December 2020.

Requested information
with diverse fuel types promoted flexibility in providing energy for the BES should one fuel type become unavailable. Reserve margins are planned so that deficiency in capacity to meet daily peak demand (Loss of Load Expectation {LOLE}) did not exceed one day-in-ten-years. LOLE is calculated from probabilistic analysis, typically using generating unit forced outage rates based on random equipment failures derived from its historic performance. The targeted level of one event every ten years is traditionally based on daily peaks (rather than hourly energy obligations). Additional insights can be gained through these methods by calculating Loss-of-Load-Hours (LOLH) and expected unserved energy (EUE) based on the mean-time-to-repair (MTTR) unit averages. Today, the transition from coal and nuclear generation to wind, solar, natural gas (with and without oil back up), distributed energy resources, and hybrid (renewables plus energy storage) resources is creating a more complex scenario and highlighting the need for energy assurance. Installed generating capacity analysis alone is not sufficient to ensure a reliable supply of energy for the BES. The proliferation of intermittent renewable generation in the resource mix increases the importance of having precisely controllable resources with sufficient fuel available, ready to respond when needed. The increasing prevalence of distribution-level resources and flexible load programs also introduces added volatility into energy forecasts, further complicating energy reliability assessments. Supply intermittency and demand volatility both require the dispatchable generation fleet to be available and flexible enough to respond when called upon. These factors can also lead to unexpected and unstudied energy issues in non-peak hours, a risk that would not be identified by traditional analyses focused on capacity reserve margins across peak demand periods. The transition to more intermittent resources is increasing the reliance on natural gas as the fuel needed for dispatchable resources that can promote energy assurance; however, uncertainty is still an issue if the natural gas-fueled resources are subject to fuel curtailment or interruption (by virtue of fuel acquisition contracts) during peak fuel demands which often correspond with winter-peak electric demands. Additionally, the design of natural gas pipeline systems and the availability of back-up natural gas feeders can impact individual generators and the BES under pipeline disruption scenarios. The intermittency of renewable generation, demand volatility, the need for sufficient flexibility from balancing generation resources, and the potential for natural gas supply interruptions all combine to highlight the need for energy reliability assessments that analyze all hours of a given study period rather than just across the peak hours. Energy assurance and fuel assurance risks are becoming more apparent as extreme weather has resulted in energy deficits (as opposed to capacity deficits) in recent years. During the past 10 years, multiple extreme events have jeopardized the BES.

Requested information
In February 2011[2], an arctic cold front in the southwest United States resulted in generation outages and natural gas facility outages. In January 2014[3], a polar vortex affected the central and eastern United States and Texas. Another event in 2014 triggered generation outages and natural gas availability issues. In January 2018[4], the southcentral United States experienced many generation outages resulting in emergency measures. In 2021, the Oroville hydroelectric facility was shut down when reservoir levels, due to drought conditions, dropped below its minimum operating elevation. Finally, the cold weather event of February 2021[5] impacted Mississippi, Louisiana, Arkansas, Oklahoma, and Texas. Events like these highlight the need for a new approach to reliability planning that considers the extreme conditions and variability the BES is increasingly experiencing. As part of ongoing near and long-term planning, many entities have started incorporating some limited energy reliability assessments (e.g., uncertainty around renewable output) into reliability studies that produce key metrics: LOLE, LOLH, and EUE. However, there is inconsistency among entities in whether and how the assessments are performed. TPL-001-4 calls out the loss of a large natural gas pipeline as an extreme event that should be studied for areas with significant natural gas generation, but beyond this mention, identifying and mitigating risks identified by energy reliability assessments are not addressed in existing NERC Reliability Standards. To achieve the level of consistency needed across the industry, energy reliability assessments for the planning (> one year) time horizon and the mitigation of identified risks must be mandated and codified in NERC Reliability Standard requirements.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This project will enhance reliability by requiring industry to perform energy reliability assessments to evaluate energy assurance and develop Corrective Action Plan(s) to address identified risks. Energy reliability assessments evaluate energy assurance across the Near-Term Transmission Planning and Long-Term Transmission Planning or equivalent[6] time horizon by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.
Project Scope (Define the parameters of the proposed project):

The project scope is to create or modify NERC Reliability Standards to address the following:
• Create requirement(s) to accomplish the following:
  ▪ Create defined terms (e.g., energy reliability assessment, energy assurance, extreme event analysis) as needed (refer to Appendix B for proposed definitions to key terms).
  ▪ Conduct an energy reliability assessment:
    ○ Define a period of time to be studied that appropriately considers the specific characteristics of the resources in the area being evaluated, including such properties as

[2] Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - FERC and NERC
[3] Polar_Vortex_Review
[4] 2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018
[5] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - FERC, NERC and Regional Entity Joint Staff Inquiry
[6] The phrases "Near-Term Transmission Planning" and "Long-Term Transmission Planning" are NERC Glossary terms. The drafting team may consider adding definitions to the NERC Glossary that are independent of transmission.

Requested information
the logistics involved in the replenishment of fuel and the ability to accurately forecast or assume system conditions. Time periods are expected to differ between areas due to the notable differences in electric systems, interconnected fuel delivery systems, weather, climate, operating philosophies, and other contributing factors. o Account for uncertainty related to both supply and demand across all hours of the studied period, probabilistically when appropriate. Potential sources of uncertainty to be considered include but are not limited to: - Time-coupled restrictions on the availability of fuel, including the limited capability to replenish fuel at or above the rate at which it is consumed. This includes transportation of stored fuels, such as oil and coal, as well as the delivery of fuels with continuous delivery, such as natural gas. Where relevant, incorporate potential contractual limitations on fuel availability. * Outage duration informed by potential failure modes. * Flexibility/operational constraints of resources. * Disruptions to fuel delivery supply chains (e.g., pipeline outages, constraints on natural gas availability due to extreme cold). * Coincident outages of multiple independent resources. * Common mode outages not connected to fuel supply. * Variability of potential renewable profiles/availability. * Impact of energy storage resources. * Transmission capacity and deliverability to the load centers, including imports. * Correlated impact of weather and other significant events on load and generation7. * Extreme weather. • Energy reliability assessments should be required to: ▪ Include an evaluation of the unique characteristics of variable resources and their impact(s) on non-variable resources (probabilistically). ▪ Be coordinated between areas to synchronize interchange assumptions. o Be conducted on a clearly defined periodic basis and performed in each of the NERC defined[8] planning time horizons. o Be periodically validated and updated, and updated when changes to assumptions and input data nullifies an existing assessment.

[7] For example, cascading series of issues including an extreme cold weather event across a significant portion of the NERC footprint, multiple forced outages early in the morning (when there is a lack of solar resources), and inadequate availability of natural gas. A wide area impact makes depending on imports less available.
[8] https://www.nerc.com/files/glossary_of_terms.pdf

Requested information
• For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Instead, each entity will establish and document criteria as part of complying with the Standard. • When predefined criteria are not met, require development of Corrective Action Plans. • Coordinate with the drafting team that is working on the "*Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons"* SAR. • Coordinate with the NERC Electric-Gas Working Group, the North American Energy Standards Board, and the *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* drafting team to minimize duplication of efforts and ensure that non-conflicting requirements are developed.
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[9] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The detailed description and requirements of proposed standards are included in the previous section of this SAR as part of the scope. Energy assurance is an increasingly important aspect of a reliable BPS, but it is inconsistently defined and measured, and energy reliability assessments to evaluate energy assurance as part of BPS long-term planning procedures are not included in existing NERC Reliability Standards. Current standards and practices focus on capacity assessments to evaluate whether sufficient power is available to supply the BPS at peak demand; however, an analysis of energy sufficiency is required to effectively identify BES risks because of the changing resource mix, the increasing volatility of demand, and the interconnected nature of the electric power system (with external supply chains, e.g., natural gas). The *2021 ERO Reliability Risk Priorities Report* (produced by the Reliability Issues Steering Committee) and the *Ensuring Energy Adequacy with Energy-Constrained Resources* whitepaper identified these issues as significant risks to reliability for which solutions to evaluate and mitigate are required. Through a gap analysis of NERC Reliability Standards and a survey of industry stakeholders, the NERC ERATF more specifically identified the energy-related risks that need to be addressed through the Standards development process. Refer to the ERATF Technical Justification document (Appendix A) for additional information and a more detailed description of the justification. The following Reliability and Security Guidelines (available at nerc.com) and technical reference documents can serve as guides to develop standards by expanding upon the work of the EGWG to energy assurance standards:

[9] 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
• Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis • Reliability Guideline: Generating Unit Winter Weather Readiness • Reliability Guideline: Gas and Electrical Operational Coordination Considerations • Data Collection: Approaches for Probabilistic Assessments • 2020 Probabilistic: Regional Risk Scenarios Sensitivity Case • Probabilistic Adequacy and Measures Report Additionally, the ERATF, Probabilistic Assessment Working Group (PAWG), Reliability Assessment Subcommittee (RAS), and other committees as well as their work can be consulted to facilitate the development of standards requirements.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
It is not the ERATF's intention to require specific solutions to the energy-related issues identified in the assessments. This SAR is intended to propose modifications to NERC's suite of Reliability Standards to require that responsible entities further evaluate risks related to energy availability. In addition, the SAR proposes revisions to Reliability Standards that would require responsible entities to create Corrective Action Plans to address risks related to energy availability. Using a performance-based approach would allow entities to take local, state, and regional needs, as well as federal regulations and other factors as appropriate into consideration. The costs associated with this assessment are expected to be comparable to those associated with the responsible entity's activities to evaluate and address potential reliability risks to the System. The cost impact is unknown and will be considered during drafting team meetings.
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 characteristics of the BES facilities impacted by this project include: fuel type, delivery logistics (e.g., the ability to access additional fuel, sufficient road and rail networks, barges for waterway-based plants, liquefied natural gas deliveries), design, construction, and operational characteristics, etc.
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):
Primary: Planning Coordinator. Impacted: Reliability Coordinator, Distribution Provider, Balancing Authority, Transmission Operator, Transmission Owner, Generator Operator, and Generator Owner.

Requested information
Do you know of any consensus building activities[10] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The ERATF's SAR development process is a consensus building activity and includes input from its members and observers. Previous drafts of the SAR have been presented to and commented on by the Reliability and Security Technical Committee and the Member Representatives Committee members. Those comments are incorporated into the updated SAR. On February 16, 2022, the ERATF conducted an industry workshop that outlined the challenges and considerations concerning solutions for performing energy reliability assessments. On May 19, 2022, the ERATF conducted a follow up industry webinar to provide an update on how the SAR comments have been addressed.
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)?
Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination; consider the impact to the TPL, EOP and TOP standards.
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.
Three reliability guidelines and three reference documents have been published in recent years that provide valuable tools for industry to assess and manage energy risks, particularly risks related to fuel assurance. However, the continued reoccurrence of extreme events and resulting impacts on fuel and energy supplies have demonstrated that Reliability Standard(s) are needed to provide consistency across the industry in performing energy reliability assessments and mitigating identified reliability risks. Reliability and Security Guidelines (nerc.com) • Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis • Reliability Guideline: Generating Unit Winter Weather Readiness • Reliability Guideline: Gas and Electrical Operational Coordination Considerations Probabilistic Assessment Working Group (PAWG) (nerc.com) • Data Collection: Approaches for Probabilistic Assessments • 2020 Probabilistic: Regional Risk Scenarios Sensitivity Case • Probabilistic Adequacy and Measures Report

[10] 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	
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
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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2022-03 Energy Assurance with Energy-Constrained Resources Standard Authorization Requests (SARs)** by **8 p.m. Eastern, Thursday, July 21, 2022.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Dominique Thompson (via email), or at 404-217-7578.

Background Information

Energy assurance is an increasingly important aspect of a reliable Bulk Electric System (BES), but has been inconsistently defined and measured without explicit standards. The project scope will address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons which was first identified in the NERC white paper entitled *Ensuring Energy Adequacy with Energy-Constrained Resources,*[1].

This project will enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and develop Corrective Action Plan(s) to address identified risks. Energy reliability assessments evaluate energy assurance across the operations time horizons by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.

Today, the transition from coal and nuclear generation to wind, solar, natural gas (with and without oil back up), distributed energy resources, and hybrid (renewables plus energy storage) resources is creating a more complex scenario and highlighting the need for energy assurance. Installed generating capacity analysis alone is not sufficient to ensure a reliable supply of energy for the BES. The proliferation of intermittent renewable generation in the resource mix increases the importance of having precisely controllable resources with sufficient fuel available, ready to respond when needed. The increasing prevalence of distribution-level resources and flexible load programs introduces added volatility into energy forecasts, further complicating operations energy reliability assessments.

[1] Energy_Assurance_White_Paper (nerc.com)

Questions

1. Do you agree with the proposed scope as described in the SARs? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

   ☐ Yes
   ☐ No

   Comments:

2. Provide any additional comments for the SARs drafting team to consider, if desired.

   Comments:

Energy Assessment Technical Justification

Updated May 5, 2022

Introduction

Energy assurance is an increasingly important aspect of a reliable Bulk Electric System (BES) but has been inconsistently defined and measured without explicit standards, including energy assessments as part of bulk power system (BPS) operations, operational planning, and long-term planning procedures. While current standards and practices focus on capacity assessments to evaluate sufficient power to supply the BPS at peak demand, the interconnected nature of the electric power system with external supply chains (e.g., natural gas), the changing resource mix, and the increasing volatility of demand require analysis of energy sufficiency to understand BPS risks adequately. The *2021 ERO Reliability Risk Priorities Report,* produced by the Reliability Issues Steering Committee (RISC), and the *Ensuring Energy Adequacy with Energy-Constrained Resources*[1] whitepaper identify these issues as significant risks to reliability that require solutions to address and mitigate these risks. The Energy Reliability Assessment Task Force (ERATF) identified gaps in the standards through a review of NERC standards related to energy risks and a survey of industry stakeholders. These identified risks and gaps in standards highlight the need to revise Reliability Standards and/or to create new Reliability Standards to evaluate and mitigate energy risks.

The ERATF was formed to assess risks associated with unassured energy supplies. The task force was created to provide a formal process to analyze and collaborate with stakeholders to address the issues identified in the *Ensuring Energy Adequacy with Energy-Constrained Resources* whitepaper. This whitepaper identified energy sufficiency concerns related to operations, operations planning, and mid- to long-term planning time frames.

Based on the eleven questions formulated in the whitepaper, the task force created a survey questionnaire. The survey was distributed to the subgroups of the Reliability and Security Technical Committee (RSTC) and independent system operators/regional transmission organizations to gather feedback on energy assurance for three focus areas:

- Energy adequacy and flexibility for evolving resource mix
- Natural gas delivery assurance
- Metrics, procedures, and analysis

The goal of the survey was to better understand how stakeholders are evaluating their energy constraint issues and fuel availability issues by extension. The original 11 questions from the whitepaper were modified slightly to seek more specific answers that would inform the ERATF's recommendations. For example, sub questions were added to understand how specific assessment input assumptions were developed and how the impact of varying those assumptions was assessed.

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[1] Energy Assurance White Paper (nerc.com)

The survey questionnaire had 18 core questions, and NERC stakeholder groups, independent system operators, and individual utilities provided 12 responses. These responses provided a large amount of information (over 500 answers) to help evaluate the energy constraint issues.

NERC ERATF Energy Assessment Survey

In September 2021, the NERC ERATF formed a subgroup of volunteers to review all the survey responses and identify recommendations. The rigor and thoroughness of the responses was excellent, and it is clear that entities put a lot of work into their responses. On October 18, this subgroup presented high-level summaries of the responses to the 18 core questions and higher-level, generalized responses as described in the following:

- Across many of the responses, it was not always clear if entities were addressing current practices for capacity assessments or energy assessments. Many entities responded that they modify capacity assessments with higher forced outage rates and extreme scenarios to evaluate a range of operating conditions, but these are not well defined and are performed inconsistently across industry based on the energy assessment responses.
- The survey demonstrated differences in how energy assessments are performed in the three time frames (operations, operational planning, and mid- to long-term planning).
- It was unclear what operating entities do with low likelihood, high impact energy assessment results. Some provide the results publicly to stakeholders for awareness, but most do not. For predicted energy deficiencies in the operational planning time frame of one to three days, almost all entities do schedule additional capacity. Most do not provide energy assessments reflective of low likelihood, high impact events in seasonal assessments. Some respondents mentioned reviewing extreme contingencies in the longer-term planning time frame, but it is unclear if any planning actions are taken. The following contain more detail:
  - Most of the responses were focused on extreme weather scenarios. Very few comments on the evaluation criteria included other potential failure modes, including cyber-attacks or other disruptions that could impact energy assurance, specifically cyber-attacks that impact the fuel supply chain.
  - Many entities use 30 years of history to develop planning forecasts, but others responded that *"…the world climate and social policies (heating & transportation electrification) are changing fast…"* and that entities should focus and forecast the future based predicted future events more so than history, including worse case extreme weather.
- Many responded that developing forecasts and assumptions for the mid- and long-term assessments is very difficult, and it is challenging to assign levels of confidence in those forecasted assumptions. As an example, it is difficult to forecast fuel replenishment or renewable production in the 6–12 month time frame and more so in the long-term planning time frame.
- Some entities responded that the worst conditions could be in the fall or spring seasons in the future with low renewable generation rather than heat wave peak conditions if those peak conditions also included high renewable generation.

- Some entities responded that there are regional differences that may result in energy assessment reliability issues. More specifically, some operating entities have wider ranges in peak loads for extreme temperatures, some have significant fuel risks, some have extreme storm risks, some have significant forest fire risks, and some have drought risks. The reliability implications can vary regionally, so risks can vary regionally. Most responded that it is important across all of the BES industry to *"…develop common and consistent energy assessment methods…"*
- A few responded on the need to assess sufficient energy flexibility, including dispatch energy, reserves, and regulation.
- Some offered that transitioning from capacity adequacy to energy assurance can initially be performed by considering more conservative assumptions with fuel, wind, and solar as well as modeling higher probabilities of derates and extreme weather. However, more sophisticated techniques need to be developed.
- Some entities offered that, based on the February 2021 extreme cold weather events, it is clear that extreme peaks can be coincident with loss of fuel.
- Many respondents indicated that energy assessments should be performed throughout the year, not just during peak conditions, to capture the risk for fuel unavailability.
- Classic forced outage rate measurements, such as effective force outage rates demand metrics and unforced capacity constructs, are poor for assessing renewable energy assurance as they assume randomness for failures rather than coincidences. Many existing capacity valuation constructs, especially for longer term resource adequacy, do not value capacity that might support energy deficits that result from multiday loss of resources, such as loss of fuel for over a week, especially for common mode loss of regional fuel.
- Some entities offered that significant issues in the planning horizon are the assumptions regarding retirements of legacy fossil fuel resources with flexibility.
- Developing mid- to long-term assumptions is very important, like *"what to assume for non-ICAP imports"* or *"what to assume for fuel replenishment"* in seasonal time frames.
- Some use 90–10 for extreme scenario assessments while others do not.

NERC Reliability Standards Review

A set of sub-teams of the ERATF was formed to review the existing NERC Reliability Standards from the viewpoint of energy assurance and identify any gaps. The perspective of this review was addressing the assumption Reliability Standards may have that energy is always available. This assumption is now under review with the new resource mix and may not be always true without having performed an energy assessment and without monitoring the resource's ability to deliver. One team reviewed the operations planning time frame, and a second team assessed at the mid- and long-term planning time frame.

The comments from the operations planning sub-team were the following observations:

- The existing Reliability Standards do not explicitly define or require energy assessments.

- A number of the Reliability Standards depend on resources to deliver energy to adhere to the requirements, such as operating within system operating limits and interconnection reliability operating limits, contingency reserves to regulate the system, and energy characteristics—such as large ramps that may constrict or be limited by available energy. The timing of deploying energy resources to meet the demand is crucial.
- There is little understanding of critical infrastructure interdependencies and their potential impacts on power generation.
- Currently, there are insufficient tools to model and forecast wind, solar, etc. for energy assessments. Also mentioned was to consider power system modeling to create more accurate predictive tools and include dynamic modeling of the natural gas system.
- As the majority of fuel infrastructure exists beyond a single area, there is a need to understand and model the fuel infrastructure on a larger basis (i.e., effects from events outside of a specific area that can have impact on that area), so the impacts can be understood.
- Considering that NERC Reliability Standards that require the use of generation assume that fuel is available, situational awareness was mentioned. The emergency operations and transmission operations Reliability Standards and transmission operational requirements should require energy assessments. With the current Reliability Standards, an adequate analysis of the transmission system can be conducted while still not meeting the energy requirements needed for the reliable operations of the BES. It is unclear whether or not the standards are assuming that there is adequate situational awareness and it is possible to maintain sufficient energy supply. There is an energy aspect of situational awareness that is missing from the current set of Reliability Standards.
- Consider moving some elements of the NERC reliability and security guidelines[2] into NERC's Reliability Standards.

The comments and recommendations from the mid- to long-term planning sub-team include the following observations:

- The existing Reliability Standards do not explicitly require energy assessments. In a new or revised standard, consider the following attributes:
  - Add requirement(s) for extreme weather or environmental[3] events
  - Determine how much time is required to recover and prepare for the next stress event
  - Create an approach to support assessments of the impact of decarbonization plans
  - Consider the risk to natural gas supply disruption, such as natural gas being unavailable due to high demand
  - Ensure that there is adequate coordination between the operations and planning teams

[2] https://www.nerc.com/comm/Pages/Reliability-and-Security-Guidelines.aspx
[3] Extreme environmental events includes long-duration environments, such as cloud cover, smoke, no wind, etc.

   - When writing transmission planning studies, consider including other transmission equipment along with transformers
   - Studies need to account for additional characteristics (e.g., ramp rate, start/stop of units)
   - Consideration is needed for dynamic load model studies
- It was noted that the transmission planning Reliability Standards are potentially the most appropriate location to add an energy assurance requirement or that a new class of standards would need to be created.

RISC Recommendations

The *2021 ERO Reliability Risk Priorities Report*[4] developed by the RISC identifies risks related to energy security as a significant risk to the BES that needs to be managed,[5] and energy assurance metrics and standards that require energy assessment would help to mitigate these risks. The report also makes recommendations for the RSTC to address these risks.

Based on survey results of emerging risk, three of the top four ranked risks are connected to energy security and assessment issues (i.e., changing resource mix, resource adequacy and performance, and critical infrastructure interdependencies).[6] These identified risks are consistent with the risks highlighted by the ERATF's survey and standards review. The RISC's conclusions explicitly recommend the following:

> "**The RSTC should develop methods, processes, tools, metrics, and/or standard authorization requests that are needed to address energy security.** Recent experiences have demonstrated that capacity alone, given the grid transformation, is not sufficient to ensure sufficient energy is available to serve consumer needs. Capacity analysis is vital but now must be buttressed with energy assessments to ensure that the system is planned and operated in a way that provides sufficient energy during widespread, long-duration extreme conditions."

This recommendation points out that capacity analysis is insufficient for planning and operational energy assurance and the need for energy assessment to fill in gaps.

Recent Reliability Events

Energy assurance and fuel assurance risks are becoming more apparent as extreme weather has resulted in deficits in energy (rather than capacity) in recent years. During the past 10 years, there have been multiple extreme events that jeopardized the BES where energy assessments could have helped identify and mitigate them. In February 2011, there was an arctic cold front in Southwest United States that resulted in generation outages and natural gas facility outages. In January 2014, there was a polar vortex that affected Central and Eastern United States and Texas. Again, the 2014 event triggered generation outages and natural gas availability issues. In January 2018, South central United States experienced many generation outages that resulted in emergency measures. Due to drought conditions, the Oroville

[4] *2021 ERO Reliability Risk Priorities Report* Source.
[5] *2021 ERO Reliability Risk Priorities Report* classifies risks to "manage" as risks that "are emerging, imminent, and pose significant threats and where thorough strategic planning and industry collaboration are needed for risk mitigation."
[6] See figure on page 15 of the *2021 ERO Reliability Risk Priorities Report.*

hydroelectric facility was shut down when reservoir levels dropped below its minimum operating elevation in 2021. In addition, load service on the Gulf and Atlantic Coasts were also disrupted by flooding and high winds generated by Hurricane Katrina (2005) and Hurricane Sandy (2012). Finally, the February 2021 event resulted from a cold air mass that impacted Mississippi, Louisiana, Arkansas, Oklahoma, and Texas. Events like these highlight the need for a new approach to reliability planning that sufficiently considers the extremes and variability that the BES is increasingly subject to.

Recommendations

Based on the review of the questionnaire and the NERC Reliability Standards gap review by the ERATF sub-teams #1 and #2 as well as the RISC recommendations,[7] standard authorization requests shall be submitted to the RSTC. The standard authorization requests for the operations and planning horizons should request new standards or revised standards to require the following:

- Energy assessments should be conducted at regular intervals.
- Energy assessments should meet set target criteria.
- If energy assurance targets are not met, impacted entities should submit corrective action plans.

[7] *2021 RISC Report*: https://www.nerc.com/comm/RISC/Documents/RISC%20ERO%20Priorities%20Report_Final_RISC_Approved_July_8_2021_Board_Submitted_Copy.pdf

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources
Standard Authorization Request

Informal Comment Period Open through July 21, 2022

Now Available

An informal comment period for the **Project 2022-03 Energy Assurance with Energy-Constrained Resources Standard Authorization Requests (SARs)**, is open through **8 p.m. Eastern, Thursday, July 21, 2022**.

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 Standards Developer, Dominique Thompson (via email) or at 404-217-7578. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources 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:	2022-03 Energy Assurance with Energy-Constrained Resources | SARs
Comment Period Start Date:	6/22/2022
Comment Period End Date:	7/21/2022
Associated Ballots:	

There were 34 sets of responses, including comments from approximately 87 different people from approximately 65 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the proposed scope as described in the SARs? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

2. Provide any additional comments for the SARs 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
Independent Electricity System Operator	Helen Lainis	2	MRO,NA - Not Applicable,NPCC,SERC,WECC	IRC	Helen Lainis	Independent Electricity System Operator	2	NPCC
					Kathleen Goodman	ISO New England	2	NPCC
					Charles Yeung	Southwest Power Pool	2	SERC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Ali Miremadi	California ISO	2	WECC
					Greg Campoli	New York ISO	2	NPCC
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
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 -	Mark	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy -	1	RF

FirstEnergy Corporation	Garza					FirstEnergy Corporation		
					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
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC

David Burke	Orange & Rockland Utilities	3	NPCC
Harish Vijay Kumar	IESO	2	NPCC
David Kiguel	Independent	7	NPCC
Nick Kowalczyk	Orange and Rockland	1	NPCC
Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	5	NPCC
Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
Nurul Abser	NB Power Corporation	1	NPCC
Randy MacDonald	NB Power Corporation	2	NPCC
Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC

					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC

1. Do you agree with the proposed scope as described in the SARs? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	
It would be very difficult to assess all of the different scenarios. This would require the development of thousands of different hypothetical models to run contingencies against. In the end, any gaps that are identified from these hypothetical studies would be impractical to justify mitigation five plus years out. Proving with evidence that we studied all possible scenarios for all hours would be a substantial burden on the industry. Another area of concern is that the audit would be highly subjective. We recommend this be developed in a best practices document rather than a compliance standard.	
Likes 1	Oncor Electric Delivery, 1, Khan Gul
Dislikes 0	
Response	
Gul Khan - Oncor Electric Delivery - 1 - Texas RE	
Answer	No
Document Name	
Comment	
The proposed scope is very broad and it isn't clear as to how effective the effort put in, in terms of Corrective Action Plans, can be.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF appreciates the opportunity to comment on the Project 2022-03 SARs. The NAGF provides the following comments for consideration: a) It is the NAGF's opinion that the SARs are generally well written.	

b) Please elaborate on and provide clarification as to how the creation of the defined terms will be accomplished. Will this be undertaken by the Standard Drafting Team? Are these defined terms intended for inclusion in the NERC Glossary of Terms?

c) The SARs appear to be broadly written and does not provide the specifics regarding the proposed deliverables in the "Detailed Description" section. This is critical to ensuring the Standard Drafting Team has the proper direction to move the project forward and to produce the desired results.

Likes 0	
Dislikes 0	

Response

Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6

Answer	No
Document Name	

Comment

This current draft looks at Energy Assurance only from a supply-side point of view. System conditions that affect *delivery* of adequate supplies are also problem areas that need to be addressed. The conditions listed can also affect transmission availability. In addition, the recently-common practice of shutting off power as a means of fire prevention in lieu of having adequate system capability to withstand wind while energized is an Energy Assurance issue, although not a reliability one at the BES level, so far.

It is recommended that this SAR action consider the following ideas:

- While extensively showing concern for fuel and variable resources it neglects to consider the impacts of all types of storage. Consider broadening the scope to specifically include energy storage and the terminology associated with energy storage.
- To maintain highly evolved TPL and TOP standard families, requirements towards generation fuel supplies should be included within a different Reliability Standard.

Energy storage should be considered and analyzed in the scope of this project. It is realistically the most limited fuel resource, and it should be thoroughly discussed and analyzed in depth. As a limited resource energy storage is normally measured in hours and not days like typical fuel supplies. In addition, to benefit from storage as a resource it should not be depleted, fully discharged, and/or needed for reserves. Furthermore, In the future when evaluating energy assurance and constrained resources storage must be accounted for in size (MW) and in duration (MWH), this will prevent excluding future electrical system composition which is an important part of the analysis.

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment

ERCOT generally agrees with the purpose and scope of this project. However, ERCOT is concerned the specific a solution – using a corrective action plan (CAP) to resolve resource adequacy issues.

Resource adequacy involves public policy and markets as well as reliability. A PC or RC may identify resolutions to issues identified in studies or assessments they perform with changes in each of those areas, but are not necessarily the appropriate entity to act on the resolution. ERCOT encourages the standard drafting team (SDT) to consider mandating studies to identify issues and possible solutions to inform policy makers and NERC entities. At the same time, the SDT should proceed with caution to ensure resulting standard changes do not implicate changes to market design or state commission rules.

The SAR provides the SDT flexibility to identify issues and solutions as well as to identify where to document new requirements. However, specifically requiring a CAP appears premature. A CAP is a defined NERC term and, generally, identifies actions to remedy a problem *within* an entity; it does not define or assign actions to *other* entities. The SDT should have flexibility to determine how to address identified issues.

Additionally, NERC Registered Entities may not have vision to or control of all issues and entities in the fuel delivery supply chain. The Planning Coordinator and Reliability Coordinator may have certain information but have very little impact on generation availability. Generator Owners and Operators, on the other hand, have insight into unit availability, but may not be able to affect change. Further, public policy may create additional challenges. For example, in Texas, by rule, residential gas service has priority over power generation gas service, which can reduce the value of an assessment.

As such, ERCOT recommends modifying the SAR to give the SDT flexibility to determine how identified solutions are to be implemented while considering the issues addressed in these comments.

Likes 0	
Dislikes 0	
Response	

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

While AZPS agrees that there is a need to accurately assess Resource Adequacy, AZPS does not agree that this type of assessment should be included in Transmission Planning or Transmission Operations standards. These functions do not control generator availability and may not have adequate access to the information required to perform these types of studies, particularly in areas that have a single Transmission Planner or Planning Coordinator.

Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	No

Document Name	
Comment	

The scope of these two SARs appear to be the same and would seem to create significant overlap between the Standard Drafting Teams assigned to address the respective SARs. Additionally, the scope of each SAR is extremely broad and, from experience, would leave the assigned SDT(s) with a significant burden to bound the scope of their efforts to address identified issues which would likely lead to a lengthy standard development process. GTC believes that the SARs should be revised to state more specifically the issues an operations-based SDT would need to address and what a long-term planning-based SDT would likewise address.

Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6

Answer	No
Document Name	
Comment	

The affected standards by the SAR are TPL-001-5.1, EOP, and TOP. There are currently two open projects affecting the identified standards (Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 and Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination) , additionally TPL-001-5.1 has an effective date of July 1, 2023 with implementation through 2029. Establishing an additional project prior to effective dates and completion of outstanding projects, creates the potential for confusion by entities and contradiction and duplication of efforts by drafting teams. Dominion Energy recommends delaying this SAR until the existing projects have had an opportunity to complete their work and an evaluation performed if this SAR is still necessary.

Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5,6

Answer	No
Document Name	
Comment	

Constellation agrees with the goal of the project to provide better energy assurance assessments and metrics. This is a timely and necessary project given the risks posed by extreme weather and other man-made disruptive events. Fuel security is a critical topic given its importance to the resiliency and reliability of the electric grid. Nuclear units provide fuel-secure, carbon-free baseload generation, yet have faced premature retirement in certain cases due to the market not appropriately compensating these attributes. Fuel security is thus a serious emerging issue affecting grid reliability as fuel-secure baseload carbon-free generators that are not appropriately compensated exit the market and use of natural gas generators susceptible to fuel supply interruption increase.

As drafted, the SARs are broadly written and do not provide enough detail on what baseline elements need to be considered in such assessments to ensure the assessments are effectively considering risks to fuel security and grid reliability. We recommend that the description of the industry need, purpose/goal, and project scope be revised to more precisely target the assessment gap that needs to be filled by the project with respect to energy assurance assessments and fuel security. We also suggest that the SAR include a requirement for NERC to develop a fuel security design-basis threat Reliability Guideline to ensure assessments account for a consistent baseline of threats in the assessments. The Reliability Guideline can be revised by NERC, with industry's support, over time as new threats emerge and the standard drafting team can include standard requirements to assess, at a minimum, the baseline threat elements included in the Guideline.

Constellation supports requiring action in the standard on any findings from the energy assurance assessments, but questions whether mandating Corrective Action Plans (CAP) is the most effective approach. Energy assurance issues present reliability challenges, but also will raise questions as to how existing market mechanisms currently in place should be changed (and/or new market mechanisms developed) to sufficiently insent corrective actions. The SARs should provide flexibility to the standard drafting team in the SARs to establish market mechanisms that address issues uncovered in the assessments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0

Dislikes 0

Response

Kimberly Turco - Constellation - 5,6

Answer No

Document Name

Comment

Constellation agrees with the goal of the project to provide better energy assurance assessments and metrics. This is a timely and necessary project given the risks posed by extreme weather and other man-made disruptive events. Fuel security is a critical topic given its importance to the resiliency and reliability of the electric grid. Nuclear units provide fuel-secure, carbon-free baseload generation, yet have faced premature retirement in certain cases due to the market not appropriately compensating these attributes. Fuel security is thus a serious emerging issue affecting grid reliability as fuel-secure baseload carbon-free generators that are not appropriately compensated exit the market and use of natural gas generators susceptible to fuel supply interruption increase.

As drafted, the SARs are broadly written and do not provide enough detail on what baseline elements need to be considered in such assessments to ensure the assessments are effectively considering risks to fuel security and grid reliability. We recommend that the description of the industry need, purpose/goal, and project scope be revised to more precisely target the assessment gap that needs to be filled by the project with respect to energy assurance assessments and fuel security. We also suggest that the SAR include a requirement for NERC to develop a fuel security design-basis threat Reliability Guideline to ensure assessments account for a consistent baseline of threats in the assessments. The Reliability Guideline can be revised by NERC, with industry's support, over time as new threats emerge and the standard drafting team can include standard requirements to assess, at a minimum, the baseline threat elements included in the Guideline.

Constellation supports requiring action in the standard on any findings from the energy assurance assessments, but questions whether mandating Corrective Action Plans (CAP) is the most effective approach. Energy assurance issues present reliability challenges, but also will raise questions as to how existing market mechanisms currently in place should be changed (and/or new market mechanisms developed) to sufficiently insent corrective actions. The SARs should provide flexibility to the standard drafting team in the SARs to establish market mechanisms that address issues uncovered in the assessments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	

Comment

Comments common to both the “Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons” and “Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon” SARs proposed scope:

Structural comments on the “Project Scope” section (pages 3-5):

- We believe the 1st sub-bullet (that starts with “Create defined terms…”) should be a primary bullet apart from the primary bullet that states “Create requirement(s) to accomplish the following:”. The development of defined terms under the project would not constitute a standard “requirement”, but would aid a common understanding by the industry of terms potentially to be used in the language of standard requirements developed under the project.
- The “Create requirement(s) to accomplish the following:” primary bullet should have sub-bullets that outline the possible new standard requirements to be considered. If performing “energy reliability assessments” is one of the objectives, make that a sub-bullet and then list all of the early requirement considerations for these assessments underneath. The primary bullet that states “Energy reliability assessments should be required to:”, and its sub-bullets, should be rolled under this.

The “Create defined terms…” sub-bullet ends with “(refer to Appendix B for proposed definitions to key terms)”. What/where is the “Appendix B” referred to?

Under the primary bullet “Energy reliability assessments should be required to:”, it is suggested that such assessments be “coordinated between areas to synchronize interchange assumptions”. While a laudable concept, we believe the execution of such a requirement would be challenging and therefore recommend it be removed from the scope as a potential mandatory requirement. Perhaps the entity performing the assessment should just identify what interchange assumptions were used.

Comments on the “Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon” SAR:

We believe the bullet that states “When predefined criteria are not met, require development of Corrective Action Plans” should be removed from the project scope. The purpose of the proposed energy reliability assessments for the planning horizon should be to inform the interested stakeholders based on a common understanding of NERC defined terms and entity established criteria. The entities performing these assessments may have limited authority to develop and oversee actionable Corrective Action Plans. The energy reliability assessments suggested in the SAR may only be useful to help inform stakeholders about potential energy supply challenges in the planning horizon. “Corrective actions”, which presumably in some cases will involve the addition of varying types of supply resources, will be developed and implemented by entities who have an obligation to serve and/or entities with an interest in marketing a supply resource.

Likes 0	
Dislikes 0	

Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA Transmission Planning does not agree that a SAR is warranted to address Resource Adequacy concerns. BPA Planning believes this is a Resource Adequacy issue and not a Transmission Reliability issue, which is the focus of the NERC Reliability Standards. Resource Adequacy issues are dealt with in different forums than NERC. Transmission capacity and deliverability to the load centers was not the primary issue for the recent disturbance events of the last few years in the CAISO and ERCOT footprints. Those events were primarily the result of Resource Adequacy issues, which are governed by State PUC-driven requirements, not NERC. It is inappropriate to revise Transmission Reliability Standards to force entities to carry the proper amount of Balancing Reserves needed for minimum resource reliability. Any transmission import deficiencies to an area are planned for in existing standards. In addition, Balancing Authority function applicability already exists regarding frequency performance.

It is unclear how a Reliability Standard related to Transmission Reliability can be developed that requires a CAP for resource inadequacy. The logical solution is to acquire more resources, and that is an Integrated Resource Plan/Resource Adequacy issue, not an issue that Transmission entities can resolve.

It appears LSEs or ISOs assessing energy resource adequacy are most appropriate to target for any new Standards. The problem in the ERCOT example is not having enough peak resources when a large portion either tripped off or were unavailable due to extreme weather. This is an issue for resource adequacy decision-makers, not a transmission entity.

Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Duke Energy generally supports the proposed scope but views existing SAR language as extremely broad. It is suggested SARs be amended to further define deliverables to ensure SDT work scope and direction are well defined to achieve desired results. For example, as written: (a) it would be difficult to assess the different scenarios and models needed to conduct the indicated reliability assessments, (b) it is uncertain how the requested data would be utilized, (c) it is not clear which NERC Functional Entities would perform the proposed tasks, and (d) clarity is needed on expectations regarding when corrective action plans are required. Additionally, further consideration is needed to define the types of resource inadequacy scenarios that require assessment and the expected mitigating actions that would be acceptable. The precursor assumptions to any analysis must be based on Resource Planner input from resource adequacy analysis yet there is no mention of their involvement in the SAR. The analysis proposed by the SAR due to expanded uncertainty is largely an extension of the resource adequacy process and how to mitigate inadequate availability through modifications to energy infrastructure, operations, or contracts.

Likes 0	

Dislikes 0	
Response	
Matthew Harward - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	No
Document Name	
Comment	
SPP recommends the drafting team consider other options for outlining resource adequacy goals outside of the TPL standard. TPL standards are focused on transmission facilities and may not be suitable for resource adequacy requirements, and adding requirements for resource adequacy could detract from the purpose and effectiveness of TPL. SPP would caution that NERC has limited authority over resource adequacy; with individual states having the authority for matters such as the planning reserve margin that utilities may carry and their Integrated Resource Plans (IRP) – a gap exists which the NERC standard may fail to close and render the requirements ineffective.	
Likes 0	
Dislikes 0	
Response	
Andy Bochman - DOE / Idaho National Lab - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Hi there. Appreciate the challenges the "energy transition" is bringing to both planners and operators. The new mix alone, that includes so much more generation variability is a massive issue. However, would also recommend more attention be paid to system degradation from climate change-exacerbated extreme weather phenomenon. Where backward looking IRPs have used 100- or 500-year events to describe probabilities, I'd argue those methods are no longer valid, or at least not nearly as helpful as they used to be. Recommend commttee examines the potential efficacy for planners of leveraging data from downscaled global climate models. One effort already in (early) motion is EPRI's READi resilience and adaptation initiative. https://www.epri.com/READi. Happy to contribute more if/when the time is right. Yours, Andy	
Likes 0	
Dislikes 0	
Response	
Tom Whynot - Manitoba Hydro - NA - Not Applicable - MRO	
Answer	Yes

Document Name	
Comment	

I agree with the proposed scope of the SAR's, the growing complication of intermittent power generation from a diverse sources puts the system at risk if long term planning does not provision for it, and operationally where outages are taken in excess that shortchange reliable operating reserves.

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2

Answer	Yes
Document Name	
Comment	

We generally agree with the scope, intent, and goals of the standard. The topic of energy adequacy requires more well-defined assessments, including a common set of terms defining assumptions, events, and measures. However, requiring a set of Corrective Action Plans that address self-defined voluntary criteria seems ineffective for achieving an adequate level of reliability with respect to energy adequacy. The industry should strive to define a minimum set of criteria for energy adequacy, and a minimum set of events for which the criteria must be satisfied within each Planning Authority and Reliability Coordinator area.

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

Southern Company generally supports the scope of the SAR.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	

Comment

Texas RE agrees with and supports the goal of the two Standard Authorization Requests. The FERC, NERC, Regional Entity Staff Report on the February 2021 Cold Weather Outages in Texas the South Central United States (Join Inquiry Report) noted that prior to the February 2021 event, “ERCOT, MISO, and SPP anticipated winter reserve margins of 50 percent, 49 percent, and 59 percent, respectively, in the NERC seasonal assessment.” (Joint Inquiry Report, at 210). While the Joint Inquiry Report acknowledged that these planning scenarios were not necessarily intended “to predict energy requirements and operational scenarios,” the disconnect between these capacity forecasts and the ultimate need to shed firm load during the February event highlights that requirements for responsible entities to further evaluate the risks related to energy availability as part of their operations and planning time horizon activities and then create Corrective Action Plans to address identified energy availability risks are necessary.

Texas RE particularly agrees with the proposed SARs’ focus on achieving a level of consistency across the industry in terms of energy reliability assessment implementation in the operations and planning time horizons, including accounting for uncertainty related to both supply and demand across all hours of the applicable study period. Although Texas RE agrees with the SAR that differences in electric systems, resource mixes, climate, and operating philosophies, preclude “one-sized fits all” energy reliability assessments, Texas RE does recommend the SDT consider whether certain minimum or baseline criteria can be incorporated in energy reliability assessments to drive consistency and support reliable operational and planning assumptions and the development of Corrective Action Plans where appropriate. In Texas RE’s experience, such criteria provide clarity and predictability for entities in developing energy reliability assessments and oversight expectations.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	Yes
Document Name	

Comment

ISO-NE agrees with the proposed scope of the SARs.

Likes 0	
Dislikes 0	

Response

Eve Stromer - Entergy - 1,3,5,6 - SERC

Answer	Yes
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the scope of the SARs.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
It would be relevant, to provide a simplified process for entities where a significant part of the production is ensured by a resource stored on-site.	
Likes 0	
Dislikes 0	
Response	
JT Kuehne - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
AEP is in support of both SARs on Energy Assessments with Energy-Constrained Resources and provides the following recommendations for drafting	

team's consideration when drafting new or modifications to the standards.

- Regional differences should be recognized when determining the energy assessments requirements. Definition for "extreme events" should be developed so the scenario sensitivity cases can be defined, accordingly. Extreme events are system conditions that significantly deviate from what is considered system normal (and studied under current standards) for that region for that time of the year in terms of expected load levels, availability of generation resources (by fuel type or regional renewable differences), and/or operational status of transmission facilities to deliver those generation resources to load.
- Number of required scenarios (i.e., study cases) to be considered in an energy reliability assessment should be flexible to "*account for uncertainty related to both supply and demand across **all hours of the studied period***" (as stated in the scope of the SAR on page 4).

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee

Answer	Yes
Document Name	

Comment

We generally agree with the scope, intent, and goals of the standard. The topic of energy adequacy requires more well-defined assessments, including a common set of terms defining assumptions, events, and measures. However, requiring a set of Corrective Action Plans that address self-defined voluntary criteria seems ineffective for achieving an adequate level of reliability with respect to energy adequacy. The industry should strive to define a minimum set of criteria for energy adequacy, and a minimum set of events for which the criteria must be satisfied within each Planning Authority and Reliability Coordinator area.

Likes 0	
Dislikes 0	

Response

Karen Frank - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF

Answer	Yes
Document Name	

Comment

MISO supports the joint comments from the ISO/RTO Council's Standards Review Committee. In addition, MISO provides the following comment which applies to both SARs.

Regarding proposed bullet #8, under "sources of uncertainty" (page 3 and below), existing Loss of Load Expectation (LOLE) modeling tools preclude MISO from studying the uncertainty associated with transmission capacity as a means to drive the need for system enhancements or improvements. The LOLE study used to set Planning Reserve Margin Requirements (PRMR) does not explicitly model transmission constraints; however, the capacity for each unit modeled is limited by its interconnection service. Whether a resource is deliverable is applied during the conversion of accreditation to Zonal Resource Credits (ZRC) used in the capacity market. However, the Planning Resource Auction (PRA) itself does have Capacity Import Limits, Capacity Export Limits, and Local Clearing Requirements that have to be respected in the auction clearing and can lead to different prices in different

Local Resource Zones (LRZs).

- Transmission capacity and deliverability to the load centers, including imports.

Rather, MISO addresses the issue of deliverability to load centers another way. Generators must secure sufficient transmission to meet deliverability requirements as part of the generator interconnection process.

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2 - NA - Not Applicable, Group Name IRC

Answer	Yes
Document Name	

Comment

The IRC SRC supports the concepts outlined in the draft Standards Authorization Request (SAR)s for the Planning Horizon and the Operations Horizon and appreciates the opportunity to provide input.

Following are some suggestions we believe will serve to increase the fruitfulness of this project.

1. On page 3 of the Planning Horizon SAR it states, "To achieve *the level of consistency* needed across the industry, energy reliability assessments for the planning (>one year) time horizon and the mitigation of identified risks must be mandated and codified in NERC Reliability Standard requirements." (Emphasis added)

With regard to "level of consistency," the SRC notes that many regions are already performing studies using LOLE, LOLH, EUE, etc. metrics. In addition, many regions are in the process of developing means to perform energy reliability assessment studies. Singular metrics or measurements may not translate well across regions. Therefore, the SAR needs to be broad and flexible enough to accommodate the use of different methodologies across NERC's footprint.

2. The IRC SRC is concerned with the using of the term Corrective Action Plan (CAP) to address identified risks. CAP is a NERC defined term which requires the applicable entity to develop a list of actions and an associated timetable for implementation to remedy a specific problem. There may be elements in the CAP that are not within the purview of the applicable entity to implement, and may require other stakeholders to actualize them (e.g., state/provincial regulatory authorities or governing bodies responsible for generation construction and retail electric service issues/load shedding). As such, the IRC SRC recommends that the term CAP be replaced with 'proposed plan' to recognize that the plan may require actions beyond the purview of the NERC and FERC.

3. The standard drafting team needs to build flexibility within the standards to address the fact that resolving the identified energy adequacy risks may create compliance obligations for the Responsible Entities that are beyond their purview. Any plan that is developed may not be fully implemented, as resolutions may impact NERC-registered entities that may not be named as responsible entities within the standard as well as require alignment with state/provincial resource procurement policy and approval by applicable regulatory/governing bodies.

4. Regarding proposed bullet #6 under "sources of uncertainty" (page 3 and below), the IRC SRC recommends variability be applied to all generating resources and not limit it to renewables.

- Variability of potential renewable profiles/availability.

Likes 0	
Dislikes 0	
Response	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	
Document Name	
Comment	
The SAR appropriately identifies the importance of energy reliability assessments and the development of corrective action plans re: same. There is no question that these are appropriate actions to be taken by each planning authority. Moreover, there is no question that such short term analysis as it	

relates to Operations fit within NERC's mission to ensure security of the BES.

When it comes to the *planning* directives in the SAR, NERC's role becomes more unclear. Of course, we recognize that NERC already has promulgated the TPL-001 standard to address an analysis of single largest contingencies. But the SAR proposes to have NERC, through both its standard setting and compliance process, overseeing a host of issues that are far beyond today's TPL-001 standard and therefore raise the question whether these issues are ones best addressed through the NERC process.

For one, Section 215(i)(2) of the Federal Power Act makes clear that NERC's standard setting authority does not reach into the subject of adequacy[2] Moreover, Section 215(d)(6) makes clear that should existing market rules conflict with the NERC standards, the market rules effectively trump the standards unless and until FERC rules otherwise.[3] Many regions use market tools such as capacity market accreditation requirements and obligations to achieve the goals set forth in the SAR. Finally, FERC has, through its Long Term Planning NOPR, set forth its expectations that Planning Authorities undertake these and similar analyses to better identify the impact of the changing resource mix, fuel related issues and others through a scenario development process that would then form the basis for regional planning as required under FERC Order 890 and Section 217 (the native load provisions) of the Federal Power Act. FERC's NOPR also makes clear that stakeholder input on these issues and the development of plans (which are essentially the 'corrective action plans' contemplated in the SAR as they relate to planning) are to be undertaken on a regional basis with significant input from states and stakeholders in that region.

For these reasons the NERC stakeholder body needs to ensure that this process:

a.not create a set of isolated analyses in place of the holistic future planning of vulnerabilities from the changing resource mix are analyzed consistent with the FERC NOPR (should it become a Final Rule);

b. not establish a NERC-focused stakeholder processes that, in outlining requirements of what needs to be studied, could well end up duplicating the stakeholder processes contemplated by the NOPR and

c. consider whether the NERC compliance process is the best way to 'police' the kind of planning that both the SAR and the FERC NOPR are seeking.

In short, the well-stated and well-intentioned SAR could end up:

a. either subdividing issues that need to be addressed in a more holistic way through the forward planning process contemplated by the NOPR or

b. effectively subsuming the larger planning process reforms set forth in the NOPR and causing the potential for confusion or inaction while one or more processes awaits conclusion of the other.

Moreover, the type of analyses listed in the SAR are so broad (although appropriate) that NERC's role and oversight over planning could inevitably end up with 'scope creep' that impinges on the steps that Planning Authorities need to undertake to comply with the NOPR (should it become a Final Rule in the near future) in a timely way.

PJM believes that the NERC process could be useful to identify common inputs that should be utilized in each of the regional planning processes so as to ensure that each region within an Interconnection is working off a common set of inputs and analysis. This, of course, does not mean that each region needs to come up with a singular approach or 'action plan' but would ensure that, given the interconnected nature of the BES within each Interconnection, there are some common factors that are being studied so as to avoid one region unduly 'leaning' on another solely as a result of having used entirely different factors to analyze in their planning process. PJM believes that modifying the SAR to focus more on establishing the common inputs (which may lead to an outcome that does not necessarily result in promulgation of a standard) would provide the needed consistency while still respecting regional differences within an Interconnection.

PJM also would caution that the NERC compliance process may not be the best fit for enforcing what is essentially an enhanced planning process. Such processes today are answerable both to the FERC and the states where each Planning Authority is operating or, in the case of public power, to their respective Boards and City Councils. This is even more the case with our Canadian counterparts where each provincial regulator plays a significant role in oversight of the planning processes. For these reasons, PJM would caution against automatically defaulting to the development of a standard or the imposition of the NERC audit and compliance process in this instance.

PJM appreciates the opportunity to comment and appreciates consideration of these comments. We support the goals and need for comprehensive planning for vulnerabilities as outlined in the SAR but suggest the above cautions and consideration of potential alternative paths to meet this very valid goal.

[2] 16 U.S.C. § 824o(i)(2) ("This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services.").

[3] 16 U.S.C. § 824o(d)(6) ("The final rule adopted under subsection (b)(2) shall include fair processes for the identification and timely resolution of any conflict between a reliability standard and any function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission applicable to a transmission organization. Such transmission organization shall continue to comply with such function, rule, order, tariff, rate schedule or agreement accepted, approved, or ordered by the Commission until—(A) the Commission finds a conflict exists between a reliability standard and any such provision; (B)the Commission orders a change to such provision pursuant to section 824e of this title; and (C)the ordered change becomes effective under this subchapter.").

Likes 0	
Dislikes 0	

Response

2. Provide any additional comments for the SARs drafting team to consider, if desired.

Helen Lainis - Independent Electricity System Operator - 2 - NA - Not Applicable, Group Name IRC	
Answer	
Document Name	
Comment	

1. The IRC SRC encourages the SARs drafting team to continue to consider the joint ISO/RTO Council (IRC) Policy Input filed with the NERC Board of Trustees in January 2022.

- · Allow flexibility in the standards to account for regional risks
- · Develop performance metrics to drive and justify investment when needed
- Develop complementary requirements to compel the provision of all data needed for a comprehensive energy study
- · Engage the Reliability Assessment Subcommittee to develop the technical parameters needed to perform energy assessments
- · Engage other organizations/agencies as needed to address fuel assurance and energy adequacy

Likes 0	
Dislikes 0	
Response	
Matthew Harward - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	
Document Name	
Comment	

The NERC RAS' Probabilistic Assessment Working Group that considers fuel risk in itsseasonal studies – can the objectives of this SAR be accomplished within existing processes and avoid a new standard?

Not all resources that contribute to system performance are subject to NERC registration. To be effective (and fair from a cost perspective) all resources must be included in these studies. How can that be achieved?

Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	

Duke Energy generally supports EEI's comments submitted for these SARs.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee

Answer	
Document Name	

Comment

It will be important to ensure that the assessment methodology developed is not overly prescriptive in terms of methodology and not software specific, in order to provide Planning Coordinators with the ability to tailor the analysis to their individual system and energy adequacy risks.

Definition of an appropriate energy adequacy metric (similar to the LOLE target of 1 day in 10 years) would allow areas to incorporate this into their planning processes and refer to the standard as the source of planning assumptions.

The standard should provide guidance on what contingencies are to be considered (e.g. loss of single-fuel generators supplied by a single gas pipeline system, multi-day low renewable generation periods that deplete storage resources, etc.) and tested against the selected adequacy metric.

It would be helpful to consider whether multiple levels of assessment detail should be incorporated into the standard at different time intervals (i.e. Comprehensive, Intermediate, and Interim assessments). These assessment periods may cover different time periods, and where possible, should dovetail with other resource planning assessments.

The standard should clearly outline expectations for analyzing time periods outside the peak load period (this may be inherent to the selected metric, but if not, guidance would be important).

We agree the standard should define common terms for energy assessments, including time periods to assess, minimum assumptions for demand levels, resources, transmission, and contingency events, including common modes of energy interruption, to test for energy adequacy.

We prefer to see the standards define minimum criteria that must be demonstrated under a specified set of demand, transmission, and resource assumptions while the system is subjected to a minimum set of contingency events. Some of these events may not be applicable to all areas, but they should be broad enough that each system is minimally tested for energy adequacy.

Ideally, in the long-term planning time frame Planning Authorities should be able to demonstrate that the probability of unsupplied energy demand does not exceed specified criteria, while in the operational-planning time frame, Reliability Coordinators should be able to demonstrate that the system has a sufficient energy margin to supply the specified forecasted demand, or that expected demand can be supplied while withstanding selected events.

Although conducting an analysis of extreme events is informative, we believe it is a distraction within standards, unless those events are part of the mandatory requirements. Standards should emphasize a minimum set of events that must be tested and minimum criteria that either must be demonstrated or shown to be addressed by time-limited corrective action plans.

It is understood that many parts of the grid have unique design characteristics and also potentially unique energy vulnerabilities, however, the industry should be able to define common energy adequacy criteria and a wide enough set of events that can minimally test each area for energy adequacy.

The standard should emphasize "energy adequacy", as this is a common issue for all systems, and not fuel adequacy. Although fuel interruption must be an important consideration, areas can be exposed to energy inadequacy for various reasons other than fuel shortages.

Since energy assessments and energy adequacy criteria are relatively new and not uniformly applied, the goal of energy reliability assurance may be more effectively achieved in the long run by developing these standards in stages, and focusing on the most critical or plausible aspects and the most consequential vulnerabilities first.

Likes 0	
Dislikes 0	

Response

JT Kuehne - AEP - 3,5,6

Answer	
Document Name	

Comment

On June 16, 2022, FERC issued a Notice of Proposed Rulemaking (NOPR) on “Transmission System Planning Performance requirements for Extreme Weather” which proposes to direct NERC to submit modifications to TPL-001-5.1 within one year of the effective date of a final rule. Consideration should be given to coordinating the “Energy Assessments with Energy-Constrained Resources in the Planning Time Horizons” SAR with the stakeholder comments provided to that NOPR.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

It is unclear what actions a SAR is expecting transmission entities to take regarding “Energy Assurance” concerns. The SAR seems to be implying that Transmission entities will need to take resource procurement actions. In other words, if an “Energy Assessment” is deficient, the SAR is expecting the transmission entity to somehow address the imbalance by procuring new resources. Not only is that impractical, it seems to exceed NERC functional entity boundaries.

The reliability of the Transmission system is not intrinsically impacted by resource inadequacy; load will be shed in the model if there are inadequate resources for the power flow simulations. Power flow simulations conducted to assess transmission reliability (because of physics) do not permit gen/load imbalances, and so “Energy Assessments” as-proposed would have a meaningless distinction for transmission entities assessing reliability of the transmission system.

This SAR seems focused on a '*quality of service*' concern (e.g. Loss of Load Expected, Expected Unserved Energy). PCM and other economic simulations can inform risks of energy imbalances on a time-horizon basis; but making the transmission entity responsible to take Corrective Actions to improve said '*quality of service*' concern seems to go beyond the definitions for NERC Functional Entities. Transmission entities are functionally separate from Resource Owners or Load Serving Entities. BPA believes, and suggests, it would be far more beneficial, and appropriate, for NERC to defer to the State PUCs that actually establish the acceptable quality of service regarding Resource Adequacy (LOLE and EUE targets). Revising

Transmission Reliability standards is both an ineffective and inappropriate mechanism to address this *'quality of service'* problem.

Likes 0	
Dislikes 0	

Response

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	
Document Name	

Comment

It would be relevant, to provide a simplified process for entities where a significant part of the production is ensured by a resource stored on-site.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Reference the Energy Assessments with Energy – Constrained Resources in the Planning Time Horizon SAR:

EEI suggests that the SDT reference both TPL-001-4 and the soon to be effective TPL-001-5.1 (effective on July 1, 2023) in the Industry Needs section of the SAR. While the language is the same in both versions of the TPL-001 Standard, it should be made clear the concern identified in the SAR exists in both versions of the Reliability Standard.

Additionally, Transmission Planners should be included in the list of drafting team candidates for this SAR since they play a principal role in TPL-001.

Likes 0	
Dislikes 0	

Response

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

Answer	

Document Name	
Comment	

Comments on the “Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon” SAR:

In the SAR section that addresses “which Functional Entities the proposed standard(s) should apply” (page 6), we believe the Resource Planner should be added to the primary group along with the Planning Coordinator.

The existing BAL-502-RF-03 standard, applicable in the ReliabilityFirst Corporation (RF) region, could serve as a starting point template for a NERC-wide standard for the planning horizon.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 5,6

Answer	
Document Name	
Comment	

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Alison Mackellar - Constellation - 5,6

Answer	
Document Name	
Comment	

Constellation has no additional comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Eve Stromer - Entergy - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #2.

Likes 0	
Dislikes 0	

Response

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	
Document Name	

Comment

Due to the complexity and size of this project, ERCOT believes the SDT should have sufficient, diverse membership to address the issues raised in ERCOT's response to Question 1. Further, the SDT must have the knowledge, ability and time to identify and coordinate any overlap in responsibilities and expectations in existing NERC Reliability Standards, mitigating conflicts and avoiding redundancy. Finally, the SDT should be aware of data currently provided to PCs and RCs and ensure they - or other entities - can perform assessments to acquire data necessary to perform assessments.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

FirstEnergy supports EEI's comments, which state:

Reference the Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon SAR:

EEI suggests that the SDT reference both TPL-001-4 and the soon to be effective TPL-001-5.1 (effective on July 1, 2023) in the Industry Needs section of the SAR.

While the language is the same in both versions of the TPL-001 Standard, it should be made clear the concern identified in the SAR exists in both versions of the Reliability Standard.

Additionally, Transmission Planners should be included in the list of drafting team candidates for this SAR since they play a principal role in TPL-001.

Further, FirstEnergy does not agree that a reliability standard should result in additional penalties for a GO if generating capacity requirements are not met due to a fuel shortage caused by unforeseen events. FirstEnergy generators already participate in the PJM capacity market and are required to provide generating capacity based on summer ICAP testing results. A generator is assessed financial penalties by PJM if it cannot meet its generating capacity requirements.

The RC and BA, not the GO, should be responsible for developing a CAP if generation capacity demands are not met during periods of constrained resources. It is the responsibility of the Transmission Grid Operator (e.g., PJM), not the GO, to ensure that adequate generating resources are available during periods of constrained resources. Operating characteristics of IRBs are the cause of constrained resources and mitigation actions over-and-above PJM generating capacity requirements should not be placed on fossil generation resources

For the Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons Concerned, only the RC and BA are listed as Primary Functional Entities. FirstEnergy suggests adding GO/GOP to provide that information on whether fuel availability is assured or not to RC/BA. This will prevent obtaining information from on other functional entities not directly responsible and help streamline information in a timely fashion. In summary, it should be RC/BA/GO/GOP as primary with TO/TOP/DP impacted.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	

Comment	
No additional 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 provides the following additional comments for consideration:

a) It is not clear which NERC entities will perform the proposed tasks identified. The NAGF notes that GO/GOPs in deregulated markets participate in the trading of fuel as well as power, and they must not seek, have or use in either respect any information providing an unfair advantage that is not available to other market participants.

b) Entities with the wide-area overview of generation, load, and transmission are best suited for performing energy risk assessments and developing system mitigations for energy-constrained resources.

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	

• NERC should allow and consider a mix of representatives from Operations and Planning since both SARs will be addressed simultaneously.

• The SDT should keep in mind the increase in workload and should attempt to minimize any potential burden that this type of Standard might add.

• Southern Company supports EEI’s comments submitted for this SAR.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	

No Comments.

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

- We agree the standard should define common terms for energy assessments, including time periods to assess, minimum assumptions for demand levels, resources, transmission, and contingency events, including common modes of energy interruption, to test for energy adequacy.
- We prefer to see the standards define a minimum criteria that must be demonstrated under a specified set of demand, transmission, and resource assumptions while the system is subjected to a minimum set of contingency events. Some of these events may not be applicable to all areas, but they should be broad enough that each system is minimally tested for energy adequacy.
- Ideally, in the long-term planning time frame Planning Authorities should be able to demonstrate that the probability of unsupplied energy demand does not exceed a specified criteria, while in the operational-planning time frame, Reliability Coordinators should be able to demonstrate that the system has a sufficient energy margin to supply the specified forecasted demand, or that expected demand can be supplied while withstanding selected events.
- Although conducting analysis of extreme events is informative, we believe it is a distraction within standards, unless those events are part of the mandatory requirements. Standards should emphasize a minimum set of events that must be tested and a minimum criteria that either must be demonstrated or shown to be addressed by time-limited corrective action plans.
- It is understood that many parts of the grid have unique design characteristics and also potentially unique energy vulnerabilities, however, the industry should be able to define a common energy adequacy criteria and a wide enough set of events that can minimally test each area for energy adequacy.
- The standard should emphasize "energy adequacy", as this is a common issue for all systems, and not fuel adequacy. Although fuel interruption must be an important consideration, areas can be exposed to energy inadequacy for various reasons other than fuel shortages.
- Since energy assessments and energy adequacy criteria are relatively new and not uniformly applied, the goal of energy reliability assurance may be more effectively achieved in the long run by developing these standards in stages, and focusing on the most critical or plausible aspects and the most consequential vulnerabilities first.

Likes 0	
Dislikes 0	
Response	

Tom Whynot - Manitoba Hydro - NA - Not Applicable - MRO

Answer	
Document Name	

Comment

The planning standard I expect to be the more complex of the two proposed standards to draft.

The operations standard can focus on two main criteria.

1. The benchmark for what is energy assurance considering reliability? Guaranteed to be dispatchable in a required time frame, and assurance that the Generation's upstream fuel supply is secure and will last the duration of the aggravating system condition.

2. The benchmark for what is energy assurance considering time, how long should an entity require fuel/energy assurance for?

With a planned outage(s), energy guaranteed to last the outage(s) duration.

In system intact conditions, standardize an energy assurance duration requirement (weeks/month/years? of guaranteed fuel reserves?) The qualifiying critera could be standardized on all sources, but could also differ depending on the type: nuclear, diesil, coal, natural gas, solar, wind, hydro. Some generation sources will surely be disqualified from having energy assurance, or a rating on that Gen's level of energy assurance could be created.

Likes 0	
Dislikes 0	

Response

Andy Bochman - DOE / Idaho National Lab - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

N/A. Thanks.

Likes 0	
Dislikes 0	

Response

Consideration of Comments

Project Name:	2022-03 Energy Assurance with Energy-Constrained Resources | SARs
Comment Period Start Date:	6/22/2022
Comment Period End Date:	7/21/2022
Associated Ballot(s):	

There were 34 sets of responses, including comments from approximately 87 different people from approximately 65 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 Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Do you agree with the proposed scope as described in the SARs? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

2. Provide any additional comments for the SARs drafting team to consider, 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
Independent Electricity System Operator	Helen Lainis	2	MRO,NA - Not Applicable,NPCC,SERC,WECC	IRC	Helen Lainis	Independent Electricity System Operator	2	NPCC
					Kathleen Goodman	ISO New England	2	NPCC
					Charles Yeung	Southwest Power Pool	2	SERC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Ali Miremadi	California ISO	2	WECC
					Greg Campoli	New York ISO	2	NPCC
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	3	WECC

						Utilities (Tacoma, WA)		
					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
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
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Jim Howell	Southern Company - Southern Company Services, Inc. - Gen	5	SERC

Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC Regional Standards Committee	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Harish Vijay Kumar	IESO	2	NPCC
					David Kiguel	Independent	7	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC

					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Deidre Altobell	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Cristhian Godoy	Con Ed - Consolidated Edison Co. of New York	6	NPCC
					Nurul Abser	NB Power Corporation	1	NPCC

					Randy MacDonald	NB Power Corporation	2	NPCC
					Michael Ridolfino	Central Hudson Gas and Electric	1	NPCC
					Vijay Puran	NYSPS	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					Sean Cavote	PSEG - Public Service Electric and Gas Co.	1	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					John Pearson	ISONE	2	NPCC
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Chantal Mazza	Hydro-Quebec	2	NPCC

					Michele Tondalo	United Illuminating Co.	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC

1. Do you agree with the proposed scope as described in the SARs? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	
It would be very difficult to assess all of the different scenarios. This would require the development of thousands of different hypothetical models to run contingencies against. In the end, any gaps that are identified from these hypothetical studies would be impractical to justify mitigation five plus years out. Proving with evidence that we studied all possible scenarios for all hours would be a substantial burden on the industry. Another area of concern is that the audit would be highly subjective. We recommend this be developed in a best practices document rather than a compliance standard.	
Likes 1	Oncor Electric Delivery, 1, Khan Gul

Dislikes 0	
Response	

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- To the extent possible, the SAR DT clarified the scope in the SARs.
- The Standard DT will consider your comments and suggestions during the Standard Development process.

Gul Khan - Oncor Electric Delivery - 1 - Texas RE

Answer	No
Document Name	
Comment	

The proposed scope is very broad and it isn’t clear as to how effective the effort put in, in terms of Corrective Action Plans, can be.

Likes 0	
Dislikes 0	
Response	

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- To the extent possible, the SAR DT clarified the scope in the SARs.
- The SAR DT revised the SARs to include other mitigation options in “Purpose or Goals” and “Project Scope” sections.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	
Comment	

The NAGF appreciates the opportunity to comment on the Project 2022-03 SARs. The NAGF provides the following comments for consideration:

a) It is the NAGF's opinion that the SARs are generally well written.

b) Please elaborate on and provide clarification as to how the creation of the defined terms will be accomplished. Will this be undertaken by the Standard Drafting Team? Are these defined terms intended for inclusion in the NERC Glossary of Terms?

c) The SARs appear to be broadly written and does not provide the specifics regarding the proposed deliverables in the "Detailed Description" section. This is critical to ensuring the Standard Drafting Team has the proper direction to move the project forward and to produce the desired results.

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- To the extent possible, the SAR DT clarified the scope in the SARs.
- The SAR DT revised the SARs to provide further clarity for the Standard DT.
- The Standard DT will identify any new terms and add them to NERC glossary, if appropriate.

Glenn Barry - Los Angeles Department of Water and Power - 1,3,5,6

Answer	No
Document Name	

Comment

This current draft looks at Energy Assurance only from a supply-side point of view. System conditions that affect *delivery* of adequate supplies are also problem areas that need to be addressed. The conditions listed can also affect transmission availability. In addition, the recently-common practice of shutting off power as a means of fire prevention in lieu of having adequate system capability to withstand wind while energized is an Energy Assurance issue, although not a reliability one at the BES level, so far.

It is recommended that this SAR action consider the following ideas:

- While extensively showing concern for fuel and variable resources it neglects to consider the impacts of all types of storage. Consider broadening the scope to specifically include energy storage and the terminology associated with energy storage.
- To maintain highly evolved TPL and TOP standard families, requirements towards generation fuel supplies should be included within a different Reliability Standard.

Energy storage should be considered and analyzed in the scope of this project. It is realistically the most limited fuel resource, and it should be thoroughly discussed and analyzed in depth. As a limited resource energy storage is normally measured in hours and not days like typical fuel supplies. In addition, to benefit from storage as a resource it should not be depleted, fully discharged, and/or needed for reserves. Furthermore, In the future when evaluating energy assurance and constrained resources storage must be accounted for in size (MW) and in duration (MWH), this will prevent excluding future electrical system composition which is an important part of the analysis.

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- The SAR DT has addressed your concern in the SARs.

Dana Showalter - Electric Reliability Council of Texas, Inc. - 2

Answer	No
Document Name	

Comment	
ERCOT generally agrees with the purpose and scope of this project. However, ERCOT is concerned the specific a solution – using a corrective action plan (CAP) to resolve resource adequacy issues. Resource adequacy involves public policy and markets as well as reliability. A PC or RC may identify resolutions to issues identified in studies or assessments they perform with changes in each of those areas, but are not necessarily the appropriate entity to act on the resolution. ERCOT encourages the standard drafting team (SDT) to consider mandating studies to identify issues and possible solutions to inform policy makers and NERC entities. At the same time, the SDT should proceed with caution to ensure resulting standard changes do not implicate changes to market design or state commission rules. The SAR provides the SDT flexibility to identify issues and solutions as well as to identify where to document new requirements. However, specifically requiring a CAP appears premature. A CAP is a defined NERC term and, generally, identifies actions to remedy a problem *within* an entity; it does not define or assign actions to *other* entities. The SDT should have flexibility to determine how to address identified issues. Additionally, NERC Registered Entities may not have vision to or control of all issues and entities in the fuel delivery supply chain. The Planning Coordinator and Reliability Coordinator may have certain information but have very little impact on generation availability. Generator Owners and Operators, on the other hand, have insight into unit availability, but may not be able to affect change. Further, public policy may create additional challenges. For example, in Texas, by rule, residential gas service has priority over power generation gas service, which can reduce the value of an assessment. As such, ERCOT recommends modifying the SAR to give the SDT flexibility to determine how identified solutions are to be implemented while considering the issues addressed in these comments.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:	

- To the extent possible, the SAR DT clarified the scope in the SAR.
- The SAR DT revised the SARs to include other mitigation options in “Purpose or Goals” and “Project Scope” sections.
- Language “The goal of the SARs is to address energy assurance rather than resource adequacy” was added to the “Purpose or Goal” section to better represent this goal.

Michelle Amarantos - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

While AZPS agrees that there is a need to accurately assess Resource Adequacy, AZPS does not agree that this type of assessment should be included in Transmission Planning or Transmission Operations standards. These functions do not control generator availability and may not have adequate access to the information required to perform these types of studies, particularly in areas that have a single Transmission Planner or Planning Coordinator.

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- The SAR DT has addressed your concern by identifying functional entities explicitly as part of the “Project Scope” section in both SARs.

Stephen Stafford - Georgia Transmission Corporation - NA - Not Applicable - SERC	
Answer	No
Document Name	

Comment	
The scope of these two SARs appear to be the same and would seem to create significant overlap between the Standard Drafting Teams assigned to address the respective SARs. Additionally, the scope of each SAR is extremely broad and, from experience, would leave the assigned SDT(s) with a significant burden to bound the scope of their efforts to address identified issues which would likely lead to a lengthy standard development process. GTC believes that the SARs should be revised to state more specifically the issues an operations-based SDT would need to address and what a long-term planning-based SDT would likewise address.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The SAR DT recognizes the differences of outcomes for the two SARs and during the Standard development process, we will take your comment into consideration. • The SAR DT have intentionally left the SARs broad to allow sufficient latitude to the Standard DT in their development of the standard.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 3,5,6	
Answer	No
Document Name	
Comment	
The affected standards by the SAR are TPL-001-5.1, EOP, and TOP. There are currently two open projects affecting the identified standards (Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1 and Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination) , additionally TPL-001-5.1 has an effective date of July 1, 2023 with implementation through 2029. Establishing an additional project prior to effective dates and completion of	

outstanding projects, creates the potential for confusion by entities and contradiction and duplication of efforts by drafting teams. Dominion Energy recommends delaying this SAR until the existing projects have had an opportunity to complete their work and an evaluation performed if this SAR is still necessary.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The SAR DT is aware of other related standard project and the Standard DT will coordinate with the projects impacted as specified in the "Project Scope" section	
Alison Mackellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation agrees with the goal of the project to provide better energy assurance assessments and metrics. This is a timely and necessary project given the risks posed by extreme weather and other man-made disruptive events. Fuel security is a critical topic given its importance to the resiliency and reliability of the electric grid. Nuclear units provide fuel-secure, carbon-free baseload generation, yet have faced premature retirement in certain cases due to the market not appropriately compensating these attributes. Fuel security is thus a serious emerging issue affecting grid reliability as fuel-secure baseload carbon-free generators that are not appropriately compensated exit the market and use of natural gas generators susceptible to fuel supply interruption increase. As drafted, the SARs are broadly written and do not provide enough detail on what baseline elements need to be considered in such assessments to ensure the assessments are effectively considering risks to fuel security and grid reliability. We recommend that the description of the industry need, purpose/goal, and project scope be revised to more precisely target the assessment gap that needs to be filled by the project with respect to energy assurance	

assessments and fuel security. We also suggest that the SAR include a requirement for NERC to develop a fuel security design-basis threat Reliability Guideline to ensure assessments account for a consistent baseline of threats in the assessments. The Reliability Guideline can be revised by NERC, with industry's support, over time as new threats emerge and the standard drafting team can include standard requirements to assess, at a minimum, the baseline threat elements included in the Guideline. Constellation supports requiring action in the standard on any findings from the energy assurance assessments, but questions whether mandating Corrective Action Plans (CAP) is the most effective approach. Energy assurance issues present reliability challenges, but also will raise questions as to how existing market mechanisms currently in place should be changed (and/or new market mechanisms developed) to sufficiently insent corrective actions. The SARs should provide flexibility to the standard drafting team in the SARs to establish market mechanisms that address issues uncovered in the assessments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation agrees with the goal of the project to provide better energy assurance assessments and metrics. This is a timely and necessary project given the risks posed by extreme weather and other man-made disruptive events. Fuel security is a critical topic given its importance to the resiliency and reliability of the electric grid. Nuclear units provide	

fuel-secure, carbon-free baseload generation, yet have faced premature retirement in certain cases due to the market not appropriately compensating these attributes. Fuel security is thus a serious emerging issue affecting grid reliability as fuel-secure baseload carbon-free generators that are not appropriately compensated exit the market and use of natural gas generators susceptible to fuel supply interruption increase.

As drafted, the SARs are broadly written and do not provide enough detail on what baseline elements need to be considered in such assessments to ensure the assessments are effectively considering risks to fuel security and grid reliability. We recommend that the description of the industry need, purpose/goal, and project scope be revised to more precisely target the assessment gap that needs to be filled by the project with respect to energy assurance assessments and fuel security. We also suggest that the SAR include a requirement for NERC to develop a fuel security design-basis threat Reliability Guideline to ensure assessments account for a consistent baseline of threats in the assessments. The Reliability Guideline can be revised by NERC, with industry's support, over time as new threats emerge and the standard drafting team can include standard requirements to assess, at a minimum, the baseline threat elements included in the Guideline.

Constellation supports requiring action in the standard on any findings from the energy assurance assessments, but questions whether mandating Corrective Action Plans (CAP) is the most effective approach. Energy assurance issues present reliability challenges, but also will raise questions as to how existing market mechanisms currently in place should be changed (and/or new market mechanisms developed) to sufficiently insent corrective actions. The SARs should provide flexibility to the standard drafting team in the SARs to establish market mechanisms that address issues uncovered in the assessments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- To the extent possible, the SAR DT clarified the scope in the SAR.

- The SAR DT revised the SARs to include other mitigation options in "Purpose or Goals" and "Project Scope" sections.
- The SAR DT recommends participation in the fuel assurance and fuel related reliability risk analysis guideline update next year.
- The SAR DT have intentionally left the SARs broad to allow sufficient latitude to the Standard DT in their development of the standard.

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

Comments common to both the "Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons" and "Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon" SARs proposed scope:

Structural comments on the "Project Scope" section (pages 3-5):

- We believe the 1st sub-bullet (that starts with "Create defined terms…") should be a primary bullet apart from the primary bullet that states "Create requirement(s) to accomplish the following:". The development of defined terms under the project would not constitute a standard "requirement", but would aid a common understanding by the industry of terms potentially to be used in the language of standard requirements developed under the project.
- The "Create requirement(s) to accomplish the following:" primary bullet should have sub-bullets that outline the possible new standard requirements to be considered. If performing "energy reliability assessments" is one of the objectives, make that a sub-bullet and then list all of the early requirement considerations for these assessments underneath. The primary bullet that states "Energy reliability assessments should be required to:", and its sub-bullets, should be rolled under this.

The “Create defined terms…” sub-bullet ends with “(refer to Appendix B for proposed definitions to key terms)”. What/where is the “Appendix B” referred to?

Under the primary bullet “Energy reliability assessments should be required to:”, it is suggested that such assessments be “coordinated between areas to synchronize interchange assumptions”. While a laudable concept, we believe the execution of such a requirement would be challenging and therefore recommend it be removed from the scope as a potential mandatory requirement. Perhaps the entity performing the assessment should just identify what interchange assumptions were used.

Comments on the “Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon” SAR:

We believe the bullet that states “When predefined criteria are not met, require development of Corrective Action Plans” should be removed from the project scope. The purpose of the proposed energy reliability assessments for the planning horizon should be to inform the interested stakeholders based on a common understanding of NERC defined terms and entity established criteria. The entities performing these assessments may have limited authority to develop and oversee actionable Corrective Action Plans. The energy reliability assessments suggested in the SAR may only be useful to help inform stakeholders about potential energy supply challenges in the planning horizon. “Corrective actions”, which presumably in some cases will involve the addition of varying types of supply resources, will be developed and implemented by entities who have an obligation to serve and/or entities with an interest in marketing a supply resource.

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- To the extent possible, the SAR DT clarified the scope in the SAR.
- The SAR DT revised the SARs to include other mitigation options in “Purpose or Goals” and “Project Scope” sections.
- The SAR DT believes the specifics to address the interchange comment is best left for the Standard DT.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA Transmission Planning does not agree that a SAR is warranted to address Resource Adequacy concerns. BPA Planning believes this is a Resource Adequacy issue and not a Transmission Reliability issue, which is the focus of the NERC Reliability Standards. Resource Adequacy issues are dealt with in different forums than NERC. Transmission capacity and deliverability to the load centers was not the primary issue for the recent disturbance events of the last few years in the CAISO and ERCOT footprints. Those events were primarily the result of Resource Adequacy issues, which are governed by State PUC-driven requirements, not NERC. It is inappropriate to revise Transmission Reliability Standards to force entities to carry the proper amount of Balancing Reserves needed for minimum resource reliability. Any transmission import deficiencies to an area are planned for in existing standards. In addition, Balancing Authority function applicability already exists regarding frequency performance. It is unclear how a Reliability Standard related to Transmission Reliability can be developed that requires a CAP for resource inadequacy. The logical solution is to acquire more resources, and that is an Integrated Resource Plan/Resource Adequacy issue, not an issue that Transmission entities can resolve. It appears LSEs or ISOs assessing energy resource adequacy are most appropriate to target for any new Standards. The problem in the ERCOT example is not having enough peak resources when a large portion either tripped off or were unavailable due to extreme weather. This is an issue for resource adequacy decision-makers, not a transmission entity.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:	

- To the extent possible, the SAR DT clarified the scope in the SAR.
- The SAR DT revised the SARs to include other mitigation options in “Purpose or Goals” and “Project Scope” sections.
- Language “The goal of the SARs is to address energy assurance rather than resource adequacy” was added to the “Purpose or Goal” section to better represent this goal.

Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy generally supports the proposed scope but views existing SAR language as extremely broad. It is suggested SARs be amended to further define deliverables to ensure SDT work scope and direction are well defined to achieve desired results. For example, as written: (a) it would be difficult to assess the different scenarios and models needed to conduct the indicated reliability assessments, (b) it is uncertain how the requested data would be utilized, (c) it is not clear which NERC Functional Entities would perform the proposed tasks, and (d) clarity is needed on expectations regarding when corrective action plans are required. Additionally, further consideration is needed to define the types of resource inadequacy scenarios that require assessment and the expected mitigating actions that would be acceptable. The precursor assumptions to any analysis must be based on Resource Planner input from resource adequacy analysis yet there is no mention of their involvement in the SAR. The analysis proposed by the SAR due to expanded uncertainty is largely an extension of the resource adequacy process and how to mitigate inadequate availability through modifications to energy infrastructure, operations, or contracts.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:	

- The SAR DT has addressed your concern by identifying functional entities explicitly as part of the "Project Scope" section in both SARs.
- The SAR DT have intentionally left the SARs broad to allow sufficient latitude to the Standard DT in their development of the standard.
- Language "The goal of the SARs is to address energy assurance rather than resource adequacy" was added to the "Purpose or Goal" section to better represent this goal.

Matthew Harward - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	No
Document Name	

Comment

SPP recommends the drafting team consider other options for outlining resource adequacy goals outside of the TPL standard. TPL standards are focused on transmission facilities and may not be suitable for resource adequacy requirements, and adding requirements for resource adequacy could detract from the purpose and effectiveness of TPL.

SPP would caution that NERC has limited authority over resource adequacy; with individual states having the authority for matters such as the planning reserve margin that utilities may carry and their Integrated Resource Plans (IRP) – a gap exists which the NERC standard may fail to close and render the requirements ineffective.

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- To the extent possible, the SAR DT clarified the scope in the SAR.
- The SAR DT revised the SARs to include other mitigation options in "Purpose or Goals" and "Project Scope" sections.

• Language “The goal of the SARs is to address energy assurance rather than resource adequacy” was added to the “Purpose or Goal” section to better represent this goal.	
Andy Bochman - DOE / Idaho National Lab - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Hi there. Appreciate the challenges the "energy transition" is bringing to both planners and operators. The new mix alone, that includes so much more generation variability is a massive issue. However, would also recommend more attention be paid to system degradation from climate change-exacerbated extreme weather phenomenon. Where backward looking IRPs have used 100- or 500-year events to describe probabilities, I'd argue those methods are no longer valid, or at least not nearly as helpful as they used to be. Recommend commttee examines the potential efficacy for planners of leveraging data from downscaled global climate models. One effort already in (early) motion is EPRI's READi resilience and adaptation initiative. https://www.epri.com/READi. Happy to contribute more if/when the time is right. Yours, Andy	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment.	
Tom Whynot - Manitoba Hydro - NA - Not Applicable - MRO	
Answer	Yes
Document Name	
Comment	

I agree with the proposed scope of the SAR's, the growing complication of intermittent power generation from a diverse sources puts the system at risk if long term planning does not provision for it, and operationally where outages are taken in excess that shortchange reliable operating reserves.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
We generally agree with the scope, intent, and goals of the standard. The topic of energy adequacy requires more well-defined assessments, including a common set of terms defining assumptions, events, and measures. However, requiring a set of Corrective Action Plans that address self-defined voluntary criteria seems ineffective for achieving an adequate level of reliability with respect to energy adequacy. The industry should strive to define a minimum set of criteria for energy adequacy, and a minimum set of events for which the criteria must be satisfied within each Planning Authority and Reliability Coordinator area.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The SAR DT revised the SARs to include other mitigation options in “Purpose or Goals” and “Project Scope” sections.	

• Language "The goal of the SARs is to address energy assurance rather than resource adequacy" was added to the "Purpose or Goal" section to better represent this goal.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company generally supports the scope of the SAR.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE agrees with and supports the goal of the two Standard Authorization Requests. The FERC, NERC, Regional Entity Staff Report on the February 2021 Cold Weather Outages in Texas the South Central United States (Join Inquiry Report) noted that prior to the February 2021 event, "ERCOT, MISO, and SPP anticipated winter reserve margins of 50 percent, 49 percent, and 59 percent, respectively, in the NERC seasonal assessment." (Joint Inquiry Report, at 210). While the Joint Inquiry Report acknowledged that these planning scenarios were not necessarily intended "to predict energy requirements and operational scenarios," the disconnect between these capacity forecasts and the	

ultimate need to shed firm load during the February event highlights that requirements for responsible entities to further evaluate the risks related to energy availability as part of their operations and planning time horizon activities and then create Corrective Action Plans to address identified energy availability risks are necessary. Texas RE particularly agrees with the proposed SARs' focus on achieving a level of consistency across the industry in terms of energy reliability assessment implementation in the operations and planning time horizons, including accounting for uncertainty related to both supply and demand across all hours of the applicable study period. Although Texas RE agrees with the SAR that differences in electric systems, resource mixes, climate, and operating philosophies, preclude "one-sized fits all" energy reliability assessments, Texas RE does recommend the SDT consider whether certain minimum or baseline criteria can be incorporated in energy reliability assessments to drive consistency and support reliable operational and planning assumptions and the development of Corrective Action Plans where appropriate. In Texas RE's experience, such criteria provide clarity and predictability for entities in developing energy reliability assessments and oversight expectations.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The SAR DT revised the SARs to include other mitigation options in "Purpose or Goals" and "Project Scope" sections.	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	

ISO-NE agrees with the proposed scope of the SARs.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment.	
Eve Stromer - Entergy - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the scope of the SARs.	
Likes 0	

Dislikes 0	
Response	
The SAR DT thanks you for your comment.	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
It would be relevant, to provide a simplified process for entities where a significant part of the production is ensured by a resource stored on-site.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
JT Kuehne - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
AEP is in support of both SARs on Energy Assessments with Energy-Constrained Resources and provides the following recommendations for drafting team’s consideration when drafting new or modifications to the standards. • Regional differences should be recognized when determining the energy assessments requirements. Definition for “extreme events” should be developed so the scenario sensitivity cases can be defined, accordingly. Extreme	

events are system conditions that significantly deviate from what is considered system normal (and studied under current standards) for that region for that time of the year in terms of expected load levels, availability of generation resources (by fuel type or regional renewable differences), and/or operational status of transmission facilities to deliver those generation resources to load. • Number of required scenarios (i.e., study cases) to be considered in an energy reliability assessment should be flexible to "*account for uncertainty related to both supply and demand across **all hours of the studied period***" (as stated in the scope of the SAR on page 4).	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee	
Answer	Yes
Document Name	
Comment	
We generally agree with the scope, intent, and goals of the standard. The topic of energy adequacy requires more well-defined assessments, including a common set of terms defining assumptions, events, and measures. However, requiring a set of Corrective Action Plans that address self-defined voluntary criteria seems ineffective for achieving an adequate level of reliability with respect to energy adequacy. The industry should strive to define a minimum set of criteria for energy adequacy, and a minimum set of events for which the criteria must be satisfied within each Planning Authority and Reliability Coordinator area.	
Likes 0	

Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The SAR DT revised the SARs to include other mitigation options in “Purpose or Goals” and “Project Scope” sections.	
Karen Frank - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	

MISO supports the joint comments from the ISO/RTO Council's Standards Review Committee. In addition, MISO provides the following comment which applies to both SARs.

Regarding proposed bullet #8, under “sources of uncertainty” (page 3 and below), existing Loss of Load Expectation (LOLE) modeling tools preclude MISO from studying the uncertainty associated with transmission capacity as a means to drive the need for system enhancements or improvements. The LOLE study used to set Planning Reserve Margin Requirements (PRMR) does not explicitly model transmission constraints; however, the capacity for each unit modeled is limited by its interconnection service. Whether a resource is deliverable is applied during the conversion of accreditation to Zonal Resource Credits (ZRC) used in the capacity market. However, the Planning Resource Auction (PRA) itself does have Capacity Import Limits, Capacity Export Limits, and Local Clearing Requirements that have to be respected in the auction clearing and can lead to different prices in different Local Resource Zones (LRZs).

- Transmission capacity and deliverability to the load centers, including imports.

Rather, MISO addresses the issue of deliverability to load centers another way. Generators must secure sufficient transmission to meet deliverability requirements as part of the generator interconnection process.

Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Helen Lainis - Independent Electricity System Operator - 2 - NA - Not Applicable, Group Name IRC	
Answer	Yes
Document Name	
Comment	

The IRC SRC supports the concepts outlined in the draft Standards Authorization Request (SAR)s for the Planning Horizon and the Operations Horizon and appreciates the opportunity to provide input.

Following are some suggestions we believe will serve to increase the fruitfulness of this project.

1. On page 3 of the Planning Horizon SAR it states, "To achieve *the level of consistency* needed across the industry, energy reliability assessments for the planning (>one year) time horizon and the mitigation of identified risks must be mandated and codified in NERC Reliability Standard requirements." (Emphasis added)

With regard to "level of consistency," the SRC notes that many regions are already performing studies using LOLE, LOLH, EUE, etc. metrics. In addition, many regions are in the process of developing means to perform energy reliability assessment studies. Singular metrics or measurements may not translate well across regions. Therefore, the SAR needs to be broad and flexible enough to accommodate the use of different methodologies across NERC's footprint.

2. The IRC SRC is concerned with the using of the term Corrective Action Plan (CAP) to address identified risks. CAP is a NERC defined term which requires the applicable entity to develop a list of actions and an associated timetable for implementation to remedy a specific problem. There may be elements in the CAP that are not within the purview of the applicable entity to implement, and may require other stakeholders to actualize them (e.g., state/provincial regulatory

authorities or governing bodies responsible for generation construction and retail electric service issues/load shedding). As such, the IRC SRC recommends that the term CAP be replaced with 'proposed plan' to recognize that the plan may require actions beyond the purview of the NERC and FERC. 3. The standard drafting team needs to build flexibility within the standards to address the fact that resolving the identified energy adequacy risks may create compliance obligations for the Responsible Entities that are beyond their purview. Any plan that is developed may not be fully implemented, as resolutions may impact NERC-registered entities that may not be named as responsible entities within the standard as well as require alignment with state/provincial resource procurement policy and approval by applicable regulatory/governing bodies. 4. Regarding proposed bullet #6 under "sources of uncertainty" (page 3 and below), the IRC SRC recommends variability be applied to all generating resources and not limit it to renewables. • Variability of potential renewable profiles/availability.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • To the extent possible, the SAR DT clarified the scope in the SAR. • The SAR DT revised the SARs to include other mitigation options in "Purpose or Goals" and "Project Scope" sections. • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Eric Sutlief - CMS Energy - Consumers Energy Company - 3,4,5 - RF	
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	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
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	
Likes 0	

Dislikes 0	
Response	
Elizabeth Davis - PJM Interconnection, L.L.C. - 2 - SERC,RF	
Answer	
Document Name	
Comment	

The SAR appropriately identifies the importance of energy reliability assessments and the development of corrective action plans re: same. There is no question that these are appropriate actions to be taken by each planning authority. Moreover, there is no question that such short term analysis as it relates to Operations fit within NERC's mission to ensure security of the BES.

When it comes to the *planning* directives in the SAR, NERC's role becomes more unclear. Of course, we recognize that NERC already has promulgated the TPL-001 standard to address an analysis of single largest contingencies. But the SAR proposes to have NERC, through both its standard setting and compliance process, overseeing a host of issues that are far beyond today's TPL-001 standard and therefore raise the question whether these issues are ones best addressed through the NERC process.

For one, Section 215(i)(2) of the Federal Power Act makes clear that NERC's standard setting authority does not reach into the subject of adequacy[2] Moreover, Section 215(d)(6) makes clear that should existing market rules conflict with the NERC standards, the market rules effectively trump the standards unless and until FERC rules otherwise.[3] Many regions use market tools such as capacity market accreditation requirements and obligations to achieve the goals set forth in the SAR. Finally, FERC has, through its Long Term Planning NOPR, set forth its expectations that Planning Authorities undertake these and similar analyses to better identify the impact of the changing resource mix, fuel related issues and others through a scenario development process that would then form the basis for regional planning as required under FERC Order 890 and Section 217 (the native load provisions) of the Federal Power Act. FERC's NOPR also makes clear that stakeholder input on these issues and the development of plans (which are essentially the 'corrective action plans' contemplated in the SAR as they relate to planning) are to be undertaken on a regional basis with significant input from states and stakeholders in that region.

For these reasons the NERC stakeholder body needs to ensure that this process:

a.not create a set of isolated analyses in place of the holistic future planning of vulnerabilities from the changing resource mix are analyzed consistent with the FERC NOPR (should it become a Final Rule);

b. not establish a NERC-focused stakeholder processes that, in outlining requirements of what needs to be studied, could well end up duplicating the stakeholder processes contemplated by the NOPR and

c. consider whether the NERC compliance process is the best way to 'police' the kind of planning that both the SAR and the FERC NOPR are seeking.

In short, the well-stated and well-intentioned SAR could end up:

a. either subdividing issues that need to be addressed in a more holistic way through the forward planning process contemplated by the NOPR or

b. effectively subsuming the larger planning process reforms set forth in the NOPR and causing the potential for confusion or inaction while one or more processes awaits conclusion of the other.

Moreover, the type of analyses listed in the SAR are so broad (although appropriate) that NERC's role and oversight over planning could inevitably end up with 'scope creep' that impinges on the steps that Planning Authorities need to undertake to comply with the NOPR (should it become a Final Rule in the near future) in a timely way.

PJM believes that the NERC process could be useful to identify common inputs that should be utilized in each of the regional planning processes so as to ensure that each region within an Interconnection is working off a common set of inputs and analysis. This, of course, does not mean that each region needs to come up with a singular approach or 'action plan' but would ensure that, given the interconnected nature of the BES within each Interconnection, there are some common factors that are being studied so as to avoid one region unduly 'leaning' on another solely as a result of having used entirely different factors to analyze in their planning process. PJM believes that modifying the SAR to focus more on establishing the common inputs (which may lead to an outcome that does not necessarily result in promulgation of a standard) would provide the needed consistency while still respecting regional differences within an Interconnection.

PJM also would caution that the NERC compliance process may not be the best fit for enforcing what is essentially an enhanced planning process. Such processes today are answerable both to the FERC and the states where each Planning Authority is operating or, in the case of public power, to their respective Boards and City Councils. This is even more the case with our Canadian counterparts where each provincial regulator plays a significant role in oversight of the planning processes. For these reasons, PJM would caution against automatically defaulting to the development of a standard or the imposition of the NERC audit and compliance process in this instance.

PJM appreciates the opportunity to comment and appreciates consideration of these comments. We support the goals and need for comprehensive planning for vulnerabilities as outlined in the SAR but suggest the above cautions and consideration of potential alternative paths to meet this very valid goal.

[2] 16 U.S.C. § 824o(i)(2) ("This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services.").

[3] 16 U.S.C. § 824o(d)(6) ("The final rule adopted under subsection (b)(2) shall include fair processes for the identification and timely resolution of any conflict between a reliability standard and any function, rule, order, tariff, rate schedule, or agreement accepted, approved, or ordered by the Commission applicable to a transmission organization. Such transmission organization shall continue to comply with such function, rule, order, tariff, rate schedule or agreement accepted, approved, or ordered by the Commission until—(A) the Commission finds a conflict exists between a reliability standard and any such provision; (B)the Commission orders a change to such provision pursuant to section 824e of this title; and (C)the ordered change becomes effective under this subchapter.").

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • To the extent possible, the SAR DT clarified the scope in the SAR. • The SAR DT revised the SARs to include other mitigation options in “Purpose or Goals” and “Project Scope” sections. • Language “The goal of the SARs is to address energy assurance rather than resource adequacy” was added to the “Purpose or Goal” section to better represent this goal.

2. Provide any additional comments for the SARs drafting team to consider, if desired.	
Helen Lainis - Independent Electricity System Operator - 2 - NA - Not Applicable, Group Name IRC	
Answer	
Document Name	
Comment	
1. The IRC SRC encourages the SARs drafting team to continue to consider the joint ISO/RTO Council (IRC) Policy Input filed with the NERC Board of Trustees in January 2022. • · Allow flexibility in the standards to account for regional risks • · Develop performance metrics to drive and justify investment when needed • Develop complementary requirements to compel the provision of all data needed for a comprehensive energy study • · Engage the Reliability Assessment Subcommittee to develop the technical parameters needed to perform energy assessments • · Engage other organizations/agencies as needed to address fuel assurance and energy adequacy	
Likes 0	
Dislikes 0	

Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Matthew Harward - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	
Document Name	
Comment	
The NERC RAS' Probabilistic Assessment Working Group that considers fuel risk in itsseasonal studies – can the objectives of this SAR be accomplished within existing processes and avoid a new standard? Not all resources that contribute to system performance are subject to NERC registration. To be effective (and fair from a cost perspective) all resources must be included in these studies. How can that be achieved?	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
Duke Energy generally supports EEI’s comments submitted for these SARs.	

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment.

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC Regional Standards Committee

Answer	
Document Name	

Comment

It will be important to ensure that the assessment methodology developed is not overly prescriptive in terms of methodology and not software specific, in order to provide Planning Coordinators with the ability to tailor the analysis to their individual system and energy adequacy risks.

Definition of an appropriate energy adequacy metric (similar to the LOLE target of 1 day in 10 years) would allow areas to incorporate this into their planning processes and refer to the standard as the source of planning assumptions.

The standard should provide guidance on what contingencies are to be considered (e.g. loss of single-fuel generators supplied by a single gas pipeline system, multi-day low renewable generation periods that deplete storage resources, etc.) and tested against the selected adequacy metric.

It would be helpful to consider whether multiple levels of assessment detail should be incorporated into the standard at different time intervals (i.e. Comprehensive, Intermediate, and Interim assessments). These assessment periods may cover different time periods, and where possible, should dovetail with other resource planning assessments.

The standard should clearly outline expectations for analyzing time periods outside the peak load period (this may be inherent to the selected metric, but if not, guidance would be important).

We agree the standard should define common terms for energy assessments, including time periods to assess, minimum assumptions for demand levels, resources, transmission, and contingency events, including common modes of energy interruption, to test for energy adequacy.

We prefer to see the standards define minimum criteria that must be demonstrated under a specified set of demand, transmission, and resource assumptions while the system is subjected to a minimum set of contingency events. Some of these events may not be applicable to all areas, but they should be broad enough that each system is minimally tested for energy adequacy.

Ideally, in the long-term planning time frame Planning Authorities should be able to demonstrate that the probability of unsupplied energy demand does not exceed specified criteria, while in the operational-planning time frame, Reliability Coordinators should be able to demonstrate that the system has a sufficient energy margin to supply the specified forecasted demand, or that expected demand can be supplied while withstanding selected events.

Although conducting an analysis of extreme events is informative, we believe it is a distraction within standards, unless those events are part of the mandatory requirements. Standards should emphasize a minimum set of events that must be tested and minimum criteria that either must be demonstrated or shown to be addressed by time-limited corrective action plans.

It is understood that many parts of the grid have unique design characteristics and also potentially unique energy vulnerabilities, however, the industry should be able to define common energy adequacy criteria and a wide enough set of events that can minimally test each area for energy adequacy.

The standard should emphasize "energy adequacy", as this is a common issue for all systems, and not fuel adequacy. Although fuel interruption must be an important consideration, areas can be exposed to energy inadequacy for various reasons other than fuel shortages.

Since energy assessments and energy adequacy criteria are relatively new and not uniformly applied, the goal of energy reliability assurance may be more effectively achieved in the long run by developing these standards in stages, and focusing on the most critical or plausible aspects and the most consequential vulnerabilities first.

Likes 0	

Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
JT Kuehne - AEP - 3,5,6	
Answer	
Document Name	
Comment	
On June 16, 2022, FERC issued a Notice of Proposed Rulemaking (NOPR) on "Transmission System Planning Performance requirements for Extreme Weather" which proposes to direct NERC to submit modifications to TPL-001-5.1 within one year of the effective date of a final rule. Consideration should be given to coordinating the "Energy Assessments with Energy-Constrained Resources in the Planning Time Horizons" SAR with the stakeholder comments provided to that NOPR.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

It is unclear what actions a SAR is expecting transmission entities to take regarding "Energy Assurance" concerns. The SAR seems to be implying that Transmission entities will need to take resource procurement actions. In other words, if an "Energy Assessment" is deficient, the SAR is expecting the transmission entity to somehow address the imbalance by procuring new resources. Not only is that impractical, it seems to exceed NERC functional entity boundaries.

The reliability of the Transmission system is not intrinsically impacted by resource inadequacy; load will be shed in the model if there are inadequate resources for the power flow simulations. Power flow simulations conducted to assess transmission reliability (because of physics) do not permit gen/load imbalances, and so "Energy Assessments" as-proposed would have a meaningless distinction for transmission entities assessing reliability of the transmission system.

This SAR seems focused on a '*quality of service*' concern (e.g. Loss of Load Expected, Expected Unserved Energy). PCM and other economic simulations can inform risks of energy imbalances on a time-horizon basis; but making the transmission entity responsible to take Corrective Actions to improve said '*quality of service*' concern seems to go beyond the definitions for NERC Functional Entities. Transmission entities are functionally separate from Resource Owners or Load Serving Entities. BPA believes, and suggests, it would be far more beneficial, and appropriate, for NERC to defer to the State PUCs that actually establish the acceptable quality of service regarding Resource Adequacy (LOLE and EUE targets). Revising Transmission Reliability standards is both an ineffective and inappropriate mechanism to address this '*quality of service*' problem.

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- Language "The goal of the SARs is to address energy assurance rather than resource adequacy" was added to the "Purpose or Goal" section to better represent this goal.

Carl Pineault - Hydro-Qu?bec Production - 1,5

Answer	

Document Name	
Comment	
It would be relevant, to provide a simplified process for entities where a significant part of the production is ensured by a resource stored on-site.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
Reference the Energy Assessments with Energy – Constrained Resources in the Planning Time Horizon SAR: EEI suggests that the SDT reference both TPL-001-4 and the soon to be effective TPL-001-5.1 (effective on July 1, 2023) in the Industry Needs section of the SAR. While the language is the same in both versions of the TPL-001 Standard, it should be made clear the concern identified in the SAR exists in both versions of the Reliability Standard. Additionally, Transmission Planners should be included in the list of drafting team candidates for this SAR since they play a principal role in TPL-001.	
Likes 0	

Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
Comments on the “Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon” SAR: In the SAR section that addresses “which Functional Entities the proposed standard(s) should apply” (page 6), we believe the Resource Planner should be added to the primary group along with the Planning Coordinator. The existing BAL-502-RF-03 standard, applicable in the ReliabilityFirst Corporation (RF) region, could serve as a starting point template for a NERC-wide standard for the planning horizon.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The SAR DT has addressed your concern by identifying functional entities explicitly as part of the “Project Scope” section in both SARs. • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Kimberly Turco - Constellation - 5,6	

Answer	
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison Mackellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Eve Stromer - Entergy - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and includes by reference the comments of the Edison Electric Institute (EEI) for question #2.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment.	
Dana Showalter - Electric Reliability Council of Texas, Inc. - 2	
Answer	

Document Name	
Comment	
Due to the complexity and size of this project, ERCOT believes the SDT should have sufficient, diverse membership to address the issues raised in ERCOT's response to Question 1. Further, the SDT must have the knowledge, ability and time to identify and coordinate any overlap in responsibilities and expectations in existing NERC Reliability Standards, mitigating conflicts and avoiding redundancy. Finally, the SDT should be aware of data currently provided to PCs and RCs and ensure they - or other entities - can perform assessments to acquire data necessary to perform assessments.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
FirstEnergy supports EEI's comments, which state: Reference the Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon SAR: EEI suggests that the SDT reference both TPL-001-4 and the soon to be effective TPL-001-5.1 (effective on July 1, 2023) in the Industry Needs section of the SAR.	

While the language is the same in both versions of the TPL-001 Standard, it should be made clear the concern identified in the SAR exists in both versions of the Reliability Standard.

Additionally, Transmission Planners should be included in the list of drafting team candidates for this SAR since they play a principal role in TPL-001.

Further, FirstEnergy does not agree that a reliability standard should result in additional penalties for a GO if generating capacity requirements are not met due to a fuel shortage caused by unforeseen events. FirstEnergy generators already participate in the PJM capacity market and are required to provide generating capacity based on summer ICAP testing results. A generator is assessed financial penalties by PJM if it cannot meet its generating capacity requirements.

The RC and BA, not the GO, should be responsible for developing a CAP if generation capacity demands are not met during periods of constrained resources. It is the responsibility of the Transmission Grid Operator (e.g., PJM), not the GO, to ensure that adequate generating resources are available during periods of constrained resources. Operating characteristics of IRBs are the cause of constrained resources and mitigation actions over-and-above PJM generating capacity requirements should not be placed on fossil generation resources

For the Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons Concerned, only the RC and BA are listed as Primary Functional Entities. FirstEnergy suggests adding GO/GOP to provide that information on whether fuel availability is assured or not to RC/BA. This will prevent obtaining information from on other functional entities not directly responsible and help streamline information in a timely fashion. In summary, it should be RC/BA/GO/GOP as primary with TO/TOP/DP impacted.

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- The Standard DT will consider your comments and suggestions during the Standard Development process.

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	
Comment	
No additional 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 provides the following additional comments for consideration: a) It is not clear which NERC entities will perform the proposed tasks identified. The NAGF notes that GO/GOPs in deregulated markets participate in the trading of fuel as well as power, and they must not seek, have or use in either respect any information providing an unfair advantage that is not available to other market participants. b) Entities with the wide-area overview of generation, load, and transmission are best suited for performing energy risk assessments and developing system mitigations for energy-constrained resources.	
Likes 0	
Dislikes 0	
Response	

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
• NERC should allow and consider a mix of representatives from Operations and Planning since both SARs will be addressed simultaneously. • The SDT should keep in mind the increase in workload and should attempt to minimize any potential burden that this type of Standard might add. • Southern Company supports EEI’s comments submitted for this SAR.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	
Document Name	
Comment	

No Comments.	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	
Document Name	
Comment	

- We agree the standard should define common terms for energy assessments, including time periods to assess, minimum assumptions for demand levels, resources, transmission, and contingency events, including common modes of energy interruption, to test for energy adequacy.
- We prefer to see the standards define a minimum criteria that must be demonstrated under a specified set of demand, transmission, and resource assumptions while the system is subjected to a minimum set of contingency events. Some of these events may not be applicable to all areas, but they should be broad enough that each system is minimally tested for energy adequacy.
- Ideally, in the long-term planning time frame Planning Authorities should be able to demonstrate that the probability of unsupplied energy demand does not exceed a specified criteria, while in the operational-planning time frame, Reliability Coordinators should be able to demonstrate that the system has a sufficient energy margin to supply the specified forecasted demand, or that expected demand can be supplied while withstanding selected events.
- Although conducting analysis of extreme events is informative, we believe it is a distraction within standards, unless those events are part of the mandatory requirements. Standards should emphasize a minimum set of events that must be tested and a minimum criteria that either must be demonstrated or shown to be addressed by time-limited corrective action plans.

- It is understood that many parts of the grid have unique design characteristics and also potentially unique energy vulnerabilities, however, the industry should be able to define a common energy adequacy criteria and a wide enough set of events that can minimally test each area for energy adequacy.
- The standard should emphasize "energy adequacy", as this is a common issue for all systems, and not fuel adequacy. Although fuel interruption must be an important consideration, areas can be exposed to energy inadequacy for various reasons other than fuel shortages.
- Since energy assessments and energy adequacy criteria are relatively new and not uniformly applied, the goal of energy reliability assurance may be more effectively achieved in the long run by developing these standards in stages, and focusing on the most critical or plausible aspects and the most consequential vulnerabilities first.

Likes 0	
Dislikes 0	

Response

The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows:

- The Standard DT will consider your comments and suggestions during the Standard Development process.

Tom Whynot - Manitoba Hydro - NA - Not Applicable - MRO

Answer	
Document Name	

Comment

The planning standard I expect to be the more complex of the two proposed standards to draft.

The operations standard can focus on two main criteria.

1. The benchmark for what is energy assurance considering reliability? Guaranteed to be dispatchable in a required time frame, and assurance that the Generation's upstream fuel supply is secure and will last the duration of the aggravating system condition. 2. The benchmark for what is energy assurance considering time, how long should an entity require fuel/energy assurance for? With a planned outage(s), energy guaranteed to last the outage(s) duration. In system intact conditions, standardize an energy assurance duration requirement (weeks/month/years? of guaranteed fuel reserves?) The qualifiying critera could be standardized on all sources, but could also differ depending on the type: nuclear, diesil, coal, natural gas, solar, wind, hydro. Some generation sources will surely be disqualified from having energy assurance, or a rating on that Gen's level of energy assurance could be created.	
Likes 0	
Dislikes 0	
Response	
The SAR DT thanks you for your comment. The SAR DT's responses to address your comments are as follows: • The Standard DT will consider your comments and suggestions during the Standard Development process.	
Andy Bochman - DOE / Idaho National Lab - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
N/A. Thanks.	
Likes 0	
Dislikes 0	

Response

1. Question 1	
Submitter's Name	
Answer	Y/N
Document Name	(if an attachment is provided by submitter)
Comment	
Submitter's comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	
Submitter's Name	
Answer	Y/N
Document Name	(if an attachment to comments is provided by submitter)
Comment	
Submitter's comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

Submitter's Name (group info also provided)	
Answer	Y/N
Document Name	(if an attachment to comments is provided by submitter)
Comment	
Submitter's comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

2. Question 2

Submitter's Name	
Answer	Y/N
Document Name	(if an attachment is provided by submitter)
Comment	
Submitter's comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments

Response	
(Drafting team's response to submitter's comments)	
Submitter's Name	
Answer	Y/N
Document Name	(if an attachment to comments is provided by submitter)
Comment	
Submitter's comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	
Submitter's Name (group info also provided)	
Answer	Y/N
Document Name	(if an attachment to comments is provided by submitter)
Comment	
Submitter's comments	
Likes 0	# of other submitters who agree with these comments
Dislikes 0	# of other submitters who disagree with these comments
Response	
(Drafting team's response to submitter's comments)	

End of Report

Unofficial Nomination Form

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2022-03 Energy Assurance with Energy-Constrained Resources** Standard Authorization Requests (SARs) drafting team members by **8 p.m. Eastern, Thursday, July 21, 2022.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information about this project is available on the project page. If you have questions, contact Standards Developer, Dominique Thompson (via email), or at 404-217-7578.

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

Previous drafting or review team experience is beneficial, but not required. A brief description of the desired qualifications, expected commitment, and other pertinent information is included below.

Energy Assurance with Energy-Constrained Resources

Energy assurance is an increasingly important aspect of a reliable Bulk Electric System (BES), but has been inconsistently defined and measured without explicit standards. The project scope will address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons which was first identified in the NERC white paper entitled *Ensuring Energy Adequacy with Energy-Constrained Resources*[1].

This project will enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and develop Corrective Action Plan(s) to address identified risks. Energy reliability assessments evaluate energy assurance across the operations time horizons by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.

Today, the transition from coal and nuclear generation to wind, solar, natural gas (with and without oil back up), distributed energy resources, and hybrid (renewables plus energy storage) resources is creating a more complex scenario and highlighting the need for energy assurance. Installed generating capacity analysis alone is not sufficient to ensure a reliable supply of energy for the BES. The proliferation of intermittent renewable generation in the resource mix increases the importance of having precisely controllable resources with sufficient fuel available, ready to respond when needed. The increasing prevalence of distribution-level resources and flexible load programs introduces added volatility into energy forecasts, further complicating operations energy reliability assessments.

[1] Energy_Assurance_White_Paper (nerc.com)

Standard(s) affected: TPL-001-5.1, EOP, and TOP
Coordinate with the *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* drafting team to minimize duplication of efforts and ensure that non-conflicting requirements are developed specifically in the TPL, EOP and TOP Standards.

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

This drafting team will address both SARs either concurrently or simultaneously; therefore, NERC is seeking individuals who possess experience in the following areas:

- Developing and implementing corrective action plans in relation to energy availability;
- Developing or implementing Balancing Authority operating plans;
- Planning and Reliability Coordination;
- Near-Term and Long-Term Transmission Planning;
- Transmission and Generation Operations;
- Familiarity with NERC Standard TPL-001-5;
- Other tasks for the planning and operation of energy reliability assessments.

Name:	
Organization:	
Address:	
Telephone:	
Email:	
Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):	
If you are currently a member of any NERC drafting team, please list each team here:	

☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):
Acknowledgement that the nominee has read and understands both the *NERC Participant Conduct Policy* and the *Standard Drafting Team Scope* documents, available on NERC Standards Resources. ☐ Yes, the nominee has read and understands these documents.

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ MRO ☐ NPCC ☐ RF	☐ SERC ☐ Texas RE ☐ WECC	☐ NA – Not Applicable

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

Select each Function[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	

[2] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

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:	

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Nomination Period Open through July 21, 2022

Now Available

Nominations are being sought for Standard Authorization Request (SAR) drafting team members through **8 p.m. Eastern, Thursday, July 21, 2022.**

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

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

The time commitment for these projects is expected to be up to two face-to-face meetings per quarter (on average two full working days each meeting) with conference calls scheduled as needed to meet the agreed-upon timeline the review or drafting team sets forth. Team members may also have side projects, either individually or by subgroup, to present to the larger team for discussion and review. Lastly, an important component of the review and drafting team effort is outreach. Members of the team will be expected to conduct industry outreach during the development process to support a successful project outcome.

This drafting team will address both SARs either concurrently or simultaneously; therefore, NERC is seeking individuals who possess experience in the following areas:

- Developing and implementing corrective action plans in relation to energy availability;
- Developing or implementing Balancing Authority operating plans;
- Planning and Reliability Coordination;
- Near-Term and Long-Term Transmission Planning;
- Transmission and Generation Operations;
- Familiarity with NERC Standard TPL-001-5;
- Other tasks for the planning and operation of energy reliability assessments.

Next Steps
The Standards Committee is expected to appoint members to the SAR drafting team in September 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 Standards Developer, Dominique Thompson (via email) or at 404-217-7578. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources 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:	Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons		
Date Submitted:	Revised on December 6, 2022		
SAR Requester			
Name:	Chair Peter Brandien on behalf of the Energy Reliability Assessment Task Force (ERATF)		
Organization:	Revised by Project 2022-03 SAR DT		
Telephone:	(413) 535-4022	Email:	pbrandien@iso-ne.com
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?):			
Unassured deliverability of fuel supplies, coincident with inconsistent output from variable renewable energy resources and volatility in forecasted load, can result in insufficient amounts of energy available from the BES needed to serve electrical demand and ensure the reliable operation of the BES throughout each hour of the time period being evaluated.[1] Historically, analyses of energy available to the BES focused on capacity reserve levels across peak-demand time periods. Generating resources and the requisite fuel were assumed available. This was a logical assumption in the past as fuel availability was assured with either firm fuel contracts (commodity plus transportation capacity), or on-site storage (e.g., oil, coal, reservoir-based hydro), or required periodic and predictable fuel replacement (e.g., nuclear). The availability of dispatchable generation			

[1] The industry need is described in the *Ensuring Energy Adequacy with Energy-Constrained Resources* white paper, presented to the RSTC, December 2020.

Requested information
with diverse fuel types promoted flexibility in providing energy for the BES should one fuel type become unavailable. Today, the transition to include more just-in-time energy resources is creating a more complex scenario and highlighting the need for energy assurance. Installed generating capacity analysis alone is not sufficient to ensure a reliable supply of energy for the BES. The proliferation of intermittent renewable generation in the resource mix increases the importance of having precisely controllable resources with sufficient fuel available, ready to respond when needed. The increasing prevalence of distribution-level resources and flexible load programs introduces added volatility into energy forecasts, further complicating operations energy reliability assessments. Supply intermittency and demand volatility both require the dispatchable generating fleet to be available and flexible enough to respond when called upon. These factors can also lead to unexpected and unstudied energy issues in non-peak hours, a risk that would not be identified by traditional analyses focusing on capacity across the peak demand periods. The transition to more intermittent resources is increasing the reliance on natural gas as the fuel needed for dispatchable resources that can promote energy assurance; however, uncertainty is still an issue if the natural gas-fueled resources are subject to fuel curtailment or interruption (by virtue of fuel acquisition contracts) during peak fuel demands which often correspond with winter-peak electric demands. Additionally, the design of natural gas pipeline systems and the availability of back-up natural gas feeders can impact individual generators and the BES under pipeline disruption scenarios. The intermittency of renewable generation, demand volatility, the need for sufficient flexibility from balancing generation resources, and the potential for natural gas supply interruptions all combine to highlight the need for energy reliability assessments that analyze all hours of a given study period rather than just the peak hours. Energy assurance and fuel assurance risks are becoming more apparent as extreme weather has resulted in energy deficits (as opposed to capacity deficits) in recent years. During the past 10 years, there have been multiple extreme events that have jeopardized the BES. In February 2011[2], an arctic cold front in the southwest United States resulted in generation outages and natural gas facility outages. In January 2014[3], a polar vortex affected the central and eastern United States and Texas. Another event in 2014 triggered generation outages and natural gas availability issues. In January 2018[4], the south-central United States experienced many generation outages resulting in emergency measures. In 2021, the Oroville hydroelectric facility was shut down when reservoir levels, due to drought conditions, dropped below its minimum operating elevation. Finally, the cold weather

2 Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - FERC and NERC
3 Polar Vortex Review
4 2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018

Requested information
event of February 2021[5] impacted Mississippi, Louisiana, Arkansas, Oklahoma, and Texas. Events like these highlight the need for a new approach to reliability operations that considers the extreme conditions and variability that the BES is increasingly experiencing. As part of ongoing operations planning, many entities have started incorporating some limited energy reliability assessments (e.g., uncertainty around renewable output) into reliability studies that produce key metrics; however, there is inconsistency among entities in whether and how the assessments are performed. To achieve the level of consistency needed across the industry, energy reliability assessments for the operations (< one year) time horizon and the mitigation of identified risks must be mandated and codified in NERC Reliability Standard requirements.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal of the SAR is to address energy assurance rather than resource adequacy. This project will enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and when predefined criteria are not met, develop Corrective Action Plan(s), Operating Plans, or other mitigating actions to address identified risks. Energy reliability assessments evaluate energy assurance across the operations time horizons[6] by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.
Project Scope (Define the parameters of the proposed project):
The project scope is to create or modify NERC Reliability Standards to address the following: • Create defined terms (e.g., energy reliability assessment, energy assurance, extreme event analysis) as needed (refer to Appendix B for proposed definitions to key terms). • Create requirement(s) and identify functional entities to accomplish the following: ▪ Conduct an energy reliability assessment: o Define a period of time to be studied within operation time horizons that appropriately considers the specific characteristics of the resources in the area being evaluated, including such properties as the logistics involved in the replenishment of fuel and the ability to accurately forecast or assume system conditions. Time periods are expected to differ between areas due to the notable differences in electric systems, interconnected fuel delivery systems, weather, climate, operating philosophies, and other contributing factors. o Include an evaluation of the unique characteristics of variable resources and their impacts(s) on non-variable resources.

[5] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - FERC, NERC and Regional Entity Joint Staff Inquiry
[6] The phrases “Operations Planning” and “Same-day Operations” are not NERC glossary terms but are referenced in the NERC document: https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

Requested information
○ Account for uncertainty related to both supply and demand across all hours of a studied period. Potential sources of uncertainty to be considered include but are not limited to: * Time-coupled restrictions on the availability of fuel, including the limited capability to replenish fuel at or above the rate at which it is consumed. This includes transportation of stored fuels, such as oil and coal, as well as the delivery of fuels with continuous delivery, such as natural gas. Where relevant, incorporate potential contractual limitations on fuel availability. * Outage duration informed by potential failure modes. * Flexibility/operational constraints of resources. * Disruptions to fuel delivery supply chains (e.g., pipeline outages, constraints on natural gas availability due to extreme cold). * Coincident outages of multiple independent resources. * Common mode outages not connected to fuel supply. * Variability of potential resource profiles/availability. * Impact of energy storage resources. * Transmission capacity and deliverability to the load centers, including imports. * Correlated impact of weather and other significant events on load and generation[7]. * Low probability/high impact weather events. • Energy reliability assessments should be required to: ▪ Be coordinated between areas to synchronize interchange assumptions. ▪ Be conducted on a clearly defined periodic basis and performed in each of the NERC defined[8] operations time horizons. ▪ Be periodically validated and updated, and updated when changes to assumptions and input data nullifies an existing assessment. • For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Alternatively, the standard would require each entity to establish and document criteria as part of complying with the Standard. The predefined criteria may be set specifically within the Standard or established and documented by each applicable entity as part of complying with the Standard.

[7] For example, cascading series of issues (including an extreme cold weather event across a significant portion of the NERC footprint), multiple forced outages early in the morning (when there is a lack of solar resources), and inadequate availability of natural gas. A wide area impact makes depending on imports less available.
[8] https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

Requested information
• When predefined criteria are not met, the responsible entity shall develop the Corrective Action Plans, Operating Plans, or other mitigating actions. • Coordinate with the NERC Electric-Gas Working Group, the North American Energy Standards Board, the *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* drafting team and other groups to minimize duplication of efforts and ensure that non-conflicting requirements are developed.
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[9] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The basis for this SAR was first identified in the NERC white paper entitled *Ensuring Energy Adequacy with Energy-Constrained Resources,*[10] which suggested several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Based on eleven questions formulated in the whitepaper, the NERC ERATF developed and distributed a survey questionnaire to subgroups of the Reliability and Security Technical Committee and Independent System Operators/Regional Transmission Organizations. The purpose was to refine the understanding of the issues identified in the whitepaper and gather feedback on energy assurance for three focus areas: • Energy assurance and flexibility for the evolving resource mix • Natural gas delivery assurance • Metrics, procedures, and analysis The goal of the survey was for the ERATF members to better understand how stakeholders are evaluating their energy constraint and fuel availability issues. The survey was based on the original eleven questions from the whitepaper and tailored to obtain more specific answers. For example, sub-questions were added to understand how specific assessment input assumptions were developed and how the impact of varying those assumptions was assessed. These responses provided a large amount of information to help evaluate the energy constraint issues. Summaries of the responses were presented to the ERATF in October 2021. Generally, the responses indicated the industry understands the purpose of energy analyses and performs energy studies. It was evident that energy issues vary from one area to another, and there are a multitude of variables to consider in terms of energy-related risks. The responses also pointed out that energy analysis is an imperative as the grid moves away from the traditional generation fleet to a resource mix that is weather dependent and energy constrained.

[9] 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.
[10] Energy Assurance White Paper (nerc.com)

Requested information
In February 2021, the ERATF conducted a workshop to showcase the types of energy analyses already being performed in both the operations and planning time horizons, as well as the tools being developed to support such studies. A key takeaway was that energy analyses are crucial, achievable, and essential. The inter-regional impact of energy-related risks requires that a consistent base method and metrics for studies be developed and employed to continue the reliable operation of the BES and providing essential reliability services. Refer to the ERATF Technical Justification document (Appendix A) for additional information.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
It is not the ERATF's intention to require specific solutions to the energy-related issues identified in the assessments. This SAR is intended to propose modifications to NERC Reliability Standards to require that responsible entities further evaluate risks related to energy availability. In addition, the SAR proposes revisions to Reliability Standards that would require responsible entities to create Corrective Action Plans, Operating Plans, or other mitigating actions to address risks related to energy availability. Using a performance-based approach would allow entities to take local, state, and regional needs, as well as federal regulations and other factors as appropriate into consideration. The costs associated with this assessment are expected to be comparable to those associated with the responsible entity's activities to evaluate and address potential reliability risks to the System. The cost impact is unknown and will be considered during drafting team meetings.
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 characteristics of the BES facilities impacted by this project include: fuel type, delivery logistics (e.g., the ability to access additional fuel, sufficient road and rail networks, barges for waterway-based plants, liquefied natural gas deliveries), design, construction, and operational characteristics, etc.
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):
Primary: Reliability Coordinator and Balancing Authority. Impacted: Distribution Provider, Transmission Operator, Transmission Owner, Generator Operator, Transmission Service Provider, Resource Planner, Transmission Planner, and Generator Owner.
Do you know of any consensus building activities[11] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The ERATF's SAR development process is a consensus building activity and includes input from its members and observers. Previous drafts of the SAR have been presented to and commented on by the Reliability and Security Technical Committee and the Member Representatives Committee members. Those comments are incorporated into the updated SAR.

[11] 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
On February 16, 2022, the ERATF conducted an industry workshop that outlined the challenges and considerations concerning solutions for performing energy reliability assessments. On May 19, 2022, the ERATF conducted a follow-up industry webinar to provide an update on how the SAR comments were addressed.
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)?
Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1, *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* and work to coordinate with any further projects that might impact this effort: consider the impact to the TPL, EOP, and TOP standards.
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.
Three reliability guidelines have been published in recent years that provide valuable tools for industry to assess and manage energy risks, particularly risks related to fuel assurance. However, the continued reoccurrence of extreme events and resulting impacts on fuel and energy supplies have demonstrated that Reliability Standard(s) are needed to provide consistency across the industry in performing energy reliability assessments and mitigating identified reliability risks. Reliability and Security Guidelines (nerc.com) • Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis • Reliability Guideline: Generating Unit Winter Weather Readiness • Reliability Guideline: Gas and Electrical Operational Coordination Considerations

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.

Reliability Principles	
☐	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 ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons		
Date Submitted:	~~June 8, 2022~~ Revised on December 6, 2022		
SAR Requester			
Name:	Chair Peter Brandien on behalf of the Energy Reliability Assessment Task Force (ERATF)		
Organization:	~~The ERATF of the Reliability and Security Technical Committee (RSTC)~~ Revised by Project 2022-03 SAR DT		
Telephone:	(413) 535-4022	Email:	pbrandien@iso-ne.com

SAR Type (Check as many as apply)	
☒ New Standard	☐ Imminent Action/ Confidential Issue (SPM Section 10)
☒ Revision to Existing Standard	☐ Variance development or revision
☒ Add, Modify or Retire a Glossary Term	☐ Other (Please specify)
☐ Withdraw/retire an Existing Standard	

Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)	
☐ Regulatory Initiation	☒ NERC Standing Committee Identified
☒ Emerging Risk (Reliability Issues Steering Committee) Identified	☐ Enhanced Periodic Review Initiated
☐ Reliability Standard Development Plan	☒ Industry Stakeholder Identified

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):
Unassured deliverability of fuel supplies, coincident with inconsistent output from variable renewable energy resources and volatility in forecasted load, can result in insufficient amounts of energy available from the BES needed to serve electrical demand and ensure the reliable operation of the BES throughout each hour of the time period being evaluated.[1] Historically, analyses of energy available to the BES focused on capacity reserve levels across peak-demand time periods. Generating resources and the requisite fuel were assumed available. This was a logical assumption in the past as fuel availability was assured with either firm fuel contracts (commodity plus transportation capacity), or on-site storage (e.g., oil, coal, reservoir-based hydro), or required

[1] The industry need is described in the *Ensuring Energy Adequacy with Energy-Constrained Resources* white paper, presented to the RSTC, December 2020.

Requested information
periodic and predictable fuel replacement (e.g., nuclear). The availability of dispatchable generation with diverse fuel types promoted flexibility in providing energy for the BES should one fuel type become unavailable. Today, the transition to include more just-in-time energy ~~from coal and nuclear generation to wind, solar, natural gas (with and without oil back up), distributed energy resources, and hybrid (renewables plus energy storage)~~ resources is creating a more complex scenario and highlighting the need for energy assurance. Installed generating capacity analysis alone is not sufficient to ensure a reliable supply of energy for the BES. The proliferation of intermittent renewable generation in the resource mix increases the importance of having precisely controllable resources with sufficient fuel available, ready to respond when needed. The increasing prevalence of distribution-level resources and flexible load programs introduces added volatility into energy forecasts, further complicating operations energy reliability assessments. Supply intermittency and demand volatility both require the dispatchable generating fleet to be available and flexible enough to respond when called upon. These factors can also lead to unexpected and unstudied energy issues in non-peak hours, a risk that would not be identified by traditional analyses focusing on capacity across the peak demand periods. The transition to more intermittent resources is increasing the reliance on natural gas as the fuel needed for dispatchable resources that can promote energy assurance; however, uncertainty is still an issue if the natural gas-fueled resources are subject to fuel curtailment or interruption (by virtue of fuel acquisition contracts) during peak fuel demands which often correspond with winter-peak electric demands. Additionally, the design of natural gas pipeline systems and the availability of back-up natural gas feeders can impact individual generators and the BES under pipeline disruption scenarios. The intermittency of renewable generation, demand volatility, the need for sufficient flexibility from balancing generation resources, and the potential for natural gas supply interruptions all combine to highlight the need for energy reliability assessments that analyze all hours of a given study period rather than just the peak hours. Energy assurance and fuel assurance risks are becoming more apparent as extreme weather has resulted in energy deficits (as opposed to capacity deficits) in recent years. During the past 10 years, there have been multiple extreme events that have jeopardized the BES. In February 2011[2], an arctic cold front in the southwest United States resulted in generation outages and natural gas facility outages. In January 2014[3], a polar vortex affected the central and eastern United States and Texas. Another event in 2014 triggered generation outages and natural gas availability issues. In January 2018[4], the south~~-~~central United States experienced many generation outages resulting in emergency measures. In 2021, the Oroville hydroelectric facility was shut down when reservoir levels,

[2] Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - FERC and NERC
[3] Polar_Vortex_Review
[4] 2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018

Requested information
due to drought conditions, dropped below its minimum operating elevation. Finally, the cold weather event of February 2021[5] impacted Mississippi, Louisiana, Arkansas, Oklahoma, and Texas. Events like these highlight the need for a new approach to reliability operations that considers the extreme conditions and variability that the BES is increasingly experiencing. As part of ongoing operations planning, many entities have started incorporating some limited energy reliability assessments (e.g., uncertainty around renewable output) into reliability studies that produce key metrics; however, there is inconsistency among entities in whether and how the assessments are performed. To achieve the level of consistency needed across the industry, energy reliability assessments for the operations (< one year) time horizon and the mitigation of identified risks must be mandated and codified in NERC Reliability Standard requirements.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal of the SAR is to address energy assurance rather than resource adequacy. This project will enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and when predefined criteria are not met, ~~potentially~~ develop Corrective Action Plan(s), Operating Plans, or other mitigating actions to address identified risks. Energy reliability assessments evaluate energy assurance across the operations time horizons[6] by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.
Project Scope (Define the parameters of the proposed project):

The project scope is to create or modify NERC Reliability Standards to address the following:
• Create defined terms (e.g., energy reliability assessment, energy assurance, extreme event analysis) as needed (refer to- Appendix B for proposed definitions to key terms).
 	
• Create requirement(s) and identify functional entities to accomplish the following:
  ▪ ~~Create defined terms (e.g., energy reliability assessment, energy assurance, extreme event analysis) as needed (refer to Appendix B for proposed definitions to key terms).~~
  ▪ Conduct an energy reliability assessment:
    o Define a period of time to be studied within operation time horizons that appropriately considers the specific characteristics of the resources in the area being evaluated, including such properties as the logistics involved in the replenishment of fuel and the ability to accurately forecast or assume system conditions. Time periods are expected to differ between areas due to the notable differences in electric systems, interconnected fuel delivery systems, weather, climate, operating philosophies, and other contributing factors.

[5] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - FERC, NERC and Regional Entity Joint Staff Inquiry
[6] The phrases "Operations Planning" and "Same-day Operations" are not NERC glossary terms but are referenced in the NERC document: https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf

Requested information
○ Include an evaluation of the unique characteristics of variable resources and their impacts(s) on non-variable resources. ○ Account for uncertainty related to both supply and demand across all hours of a studied period. Potential sources of uncertainty to be considered include but are not limited to: ~~○~~ ~~• Time-coupled restrictions on the availability of fuel, including the limited capability to replenish fuel at or above the rate at which it is consumed. This includes transportation of stored fuels, such as oil and coal, as well as the delivery of fuels with continuous delivery, such as natural gas. Where relevant, incorporate potential contractual limitations on fuel availability.~~ * ~~Outage duration informed by potential failure modes.~~Time-coupled restrictions on the availability of fuel, including the limited capability to replenish fuel at or above the rate at which it is consumed. This includes transportation of stored fuels, such as oil and coal, as well as the delivery of fuels with continuous delivery, such as natural gas. Where relevant, incorporate potential contractual limitations on fuel availability. * Outage duration informed by potential failure modes. * Flexibility/operational constraints of resources. * Disruptions to fuel delivery supply chains (e.g., pipeline outages, constraints on natural gas availability due to extreme cold). * Coincident outages of multiple independent resources. * Common mode outages not connected to fuel supply. * Variability of potential resource~~renewable~~ profiles/availability. * Impact of energy storage resources. * Transmission capacity and deliverability to the load centers, including imports. * Correlated impact of weather and other significant events on load and generation[7]. * ~~Extreme~~ Low probability/high impact ~~w~~weather events.~~.~~ • Energy reliability assessments should be required to: ~~▪ Include an evaluation of the unique characteristics of variable resources and their impact(s) on non-variable resources.~~ ▪ Be coordinated between areas to synchronize interchange assumptions.

[7] For example, cascading series of issues (including an extreme cold weather event across a significant portion of the NERC footprint), multiple forced outages early in the morning (when there is a lack of solar resources), and inadequate availability of natural gas. A wide area impact makes depending on imports less available.

Requested information
▪ Be conducted on a clearly defined periodic basis and performed in each of the NERC defined[8] operations time horizons. ▪ Be periodically validated and updated, and updated when changes to assumptions and input data nullifies an existing assessment. • For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Alternatively~~Instead~~, the standard would require each entity ~~could will~~ to establish and document criteria as part of complying with the Standard. The predefined criteria may be set specifically within the Standard or established and documented by each applicable entity as part of complying with the Standard. • When predefined criteria are not met, ~~require~~ the responsible entity shall develop ~~development of~~ the Corrective Action Plans, Operating Plans, or other mitigating actions. • ~~Coordinate with the drafting team that is working on the "Energy Assessments with Energy-Constrained Resources in the Planning Time Horizons" SAR.~~ • Coordinate with the NERC Electric-Gas Working Group, the North American Energy Standards Board, ~~and~~ the *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* drafting team and other groups to minimize duplication of efforts and ensure that non-conflicting requirements are developed.
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[9] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.*, research paper) to guide development of the Standard or definition):
The basis for this SAR was first identified in the NERC white paper entitled *Ensuring Energy Adequacy with Energy-Constrained Resources,*[10] which suggested several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Based on eleven questions formulated in the whitepaper, the NERC ERATF developed and distributed a survey questionnaire to subgroups of the Reliability and Security Technical Committee and Independent System Operators/Regional Transmission Organizations. The purpose was to refine the understanding of the issues identified in the whitepaper and gather feedback on energy assurance for three focus areas: • Energy assurance and flexibility for the evolving resource mix • Natural gas delivery assurance • Metrics, procedures, and analysis

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Requested information
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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 characteristics of the BES facilities impacted by this project include: fuel type, delivery logistics (e.g., the ability to access additional fuel, sufficient road and rail networks, barges for waterway-based plants, liquefied natural gas deliveries), design, construction, and operational characteristics, etc.

Requested information
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):
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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

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request (SAR)

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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:	Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon		
Date Submitted:	Revised on December 6, 2022		
SAR Requester			
Name:	Chair Peter Brandien on behalf of the Energy Reliability Assessment Task Force (ERATF)		
Organization:	Revised by Project 2022-03 SAR DT		
Telephone:	(413) 535-4022	Email:	pbrandien@iso-ne.com

SAR Type (Check as many as apply)	
☒ New Standard	☐ Imminent Action/ Confidential Issue (SPM Section 10)
☒ Revision to Existing Standard	☐ Variance development or revision
☒ Add, Modify or Retire a Glossary Term	☐ Other (Please specify)
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Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)	
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☒ Emerging Risk (Reliability Issues Steering Committee) Identified	☐ Enhanced Periodic Review Initiated
☐ Reliability Standard Development Plan	☒ Industry Stakeholder Identified

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[1] The industry need is described in the *Ensuring Energy Adequacy with Energy-Constrained Resources* white paper, presented to the RSTC, December 2020.

Requested information
with diverse fuel types promoted flexibility in providing energy for the BES should one fuel type become unavailable. Reserve margins are planned so that deficiency in capacity to meet daily peak demand (Loss of Load Expectation {LOLE}) did not exceed one day-in-ten-years. LOLE is calculated from probabilistic analysis, typically using generating unit forced outage rates based on random equipment failures derived from its historic performance. The targeted level of one event every ten years is traditionally based on daily peaks (rather than hourly energy obligations). Additional insights can be gained through these methods by calculating Loss-of-Load-Hours (LOLH) and expected unserved energy (EUE) based on the mean-time-to-repair (MTTR) unit averages. Today, the transition to include more just-in-time energy resources is creating a more complex scenario and highlighting the need for energy assurance. Installed generating capacity analysis alone is not sufficient to ensure a reliable supply of energy for the BES. The proliferation of intermittent renewable generation in the resource mix increases the importance of having precisely controllable resources with sufficient fuel available, ready to respond when needed. The increasing prevalence of distribution-level resources and flexible load programs also introduces added volatility into energy forecasts, further complicating energy reliability assessments. Supply intermittency and demand volatility both require the dispatchable generation fleet to be available and flexible enough to respond when called upon. These factors can also lead to unexpected and unstudied energy issues in non-peak hours, a risk that would not be identified by traditional analyses focused on capacity reserve margins across peak demand periods. The transition to more intermittent resources is increasing the reliance on natural gas as the fuel needed for dispatchable resources that can promote energy assurance; however, uncertainty is still an issue if the natural gas-fueled resources are subject to fuel curtailment or interruption (by virtue of fuel acquisition contracts) during peak fuel demands which often correspond with winter-peak electric demands. Additionally, the design of natural gas pipeline systems and the availability of back-up natural gas feeders can impact individual generators and the BES under pipeline disruption scenarios. The intermittency of renewable generation, demand volatility, the need for sufficient flexibility from balancing generation resources, and the potential for natural gas supply interruptions all combine to highlight the need for energy reliability assessments that analyze all hours of a given study period rather than just across the peak hours. Energy assurance and fuel assurance risks are becoming more apparent as extreme weather has resulted in energy deficits (as opposed to capacity deficits) in recent years. During the past 10 years, multiple extreme events that have jeopardized the BES.

Requested information
In February 2011[2], an arctic cold front in the southwest United States resulted in generation outages and natural gas facility outages. In January 2014[3], a polar vortex affected the central and eastern United States and Texas. Another event in 2014 triggered generation outages and natural gas availability issues. In January 2018[4], the south-central United States experienced many generation outages resulting in emergency measures. In 2021, the Oroville hydroelectric facility was shut down when reservoir levels, due to drought conditions, dropped below its minimum operating elevation. Finally, the cold weather event of February 2021[5] impacted Mississippi, Louisiana, Arkansas, Oklahoma, and Texas. Events like these highlight the need for a new approach to reliability planning that considers the extreme conditions and variability the BES is increasingly experiencing. As part of ongoing near and long-term planning, many entities have started incorporating some limited energy reliability assessments (e.g., uncertainty around renewable output) into reliability studies that produce key metrics: LOLE, LOLH, and EUE. However, there is inconsistency among entities in whether and how the assessments are performed. TPL-001-4 calls out the loss of a large natural gas pipeline as an extreme event that should be studied for areas with significant natural gas generation, but beyond this mention, identifying and mitigating risks identified by energy reliability assessments are not addressed in existing NERC Reliability Standards. To achieve the level of consistency needed across the industry, energy reliability assessments for the planning (> one year) time horizon and the mitigation of identified risks must be mandated and codified in NERC Reliability Standard requirements.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The goal of the SAR is to address energy assurance rather than resource adequacy. This project will enhance reliability by requiring industry to perform energy reliability assessments to evaluate energy assurance and when predefined criteria are not met, develop Corrective Action Plan(s), Operating Plans, or other mitigating actions to address identified risks. Energy reliability assessments evaluate energy assurance across the Near-Term Transmission Planning and Long-Term Transmission Planning or equivalent[6] time horizon by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.
Project Scope (Define the parameters of the proposed project):
The project scope is to create or modify NERC Reliability Standards to address the following: • Create defined terms (e.g., energy reliability assessment, energy assurance, extreme event analysis) as needed (refer to Appendix B for proposed definitions to key terms). • Create requirement(s) and identify functional entities to accomplish the following:

[2] Outages and Curtailments During the Southwest Cold Weather Event of February 1-5, 2011 - FERC and NERC
[3] Polar_Vortex_Review
[4] 2019 FERC and NERC Staff Report: The South Central United States Cold Weather Bulk Electric System Event of January 17, 2018
[5] February 2021 Cold Weather Grid Operations: Preliminary Findings and Recommendations - FERC, NERC and Regional Entity Joint Staff Inquiry
[6] The phrases "Near-Term Transmission Planning" and "Long-Term Transmission Planning" are NERC Glossary terms. The drafting team may consider adding definitions to the NERC Glossary that are independent of transmission.

Requested information
▪ Conduct an energy reliability assessment: ○ Define a period of time to be studied within planning time horizons that appropriately considers the specific characteristics of the resources in the area being evaluated, including such properties as the logistics involved in the replenishment of fuel and the ability to accurately forecast or assume system conditions. Time periods are expected to differ between areas due to the notable differences in electric systems, interconnected fuel delivery systems, weather, climate, operating philosophies, and other contributing factors. ○ Include an evaluation of the unique characteristics of variable resources and their impact(s) on non-variable resources. ○ Account for uncertainty related to both supply and demand across all hours of the studied period, probabilistically when appropriate. Potential sources of uncertainty to be considered include but are not limited to: * Time-coupled restrictions on the availability of fuel, including the limited capability to replenish fuel at or above the rate at which it is consumed. This includes transportation of stored fuels, such as oil and coal, as well as the delivery of fuels with continuous delivery, such as natural gas. Where relevant, incorporate potential contractual limitations on fuel availability. * Outage duration informed by potential failure modes. * Flexibility/operational constraints of resources. * Disruptions to fuel delivery supply chains (e.g., pipeline outages, constraints on natural gas availability due to extreme cold). * Coincident outages of multiple independent resources. * Common mode outages not connected to fuel supply. * Variability of potential resource profiles/availability. * Impact of energy storage resources. * Transmission capacity and deliverability to the load centers, including imports. * Correlated impact of weather and other significant events on load and generation[7]. * Low probability/high impact weather events.

[7] For example, cascading series of issues including an extreme cold weather event across a significant portion of the NERC footprint, multiple forced outages early in the morning (when there is a lack of solar resources), and inadequate availability of natural gas. A wide area impact makes depending on imports less available.

Requested information
• Energy reliability assessments should be required to: ▪ Be coordinated between areas to synchronize interchange assumptions. ▪ Be conducted on a clearly defined periodic basis and performed in each of the NERC defined planning time horizons. ▪ Be periodically validated and updated, and updated when changes to assumptions and input data nullifies an existing assessment. • For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Alternatively, the standard would require each entity to establish and document criteria as part of complying with the Standard. The predefined criteria may be set specifically within the Standard or established and documented by each applicable entity as part of complying with the Standard. • When predefined criteria are not met, the responsible entity shall develop the Corrective Action Plans, Operating Plans or other mitigating actions. • Coordinate with the NERC Electric-Gas Working Group, the North American Energy Standards Board, the *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* drafting team and other groups to minimize duplication of efforts and ensure that non-conflicting requirements are developed.
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[8] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
The detailed description and requirements of proposed standards are included in the previous section of this SAR as part of the scope. Energy assurance is an increasingly important aspect of a reliable BPS, but it is inconsistently defined and measured, and energy reliability assessments to evaluate energy assurance as part of BPS long-term planning procedures are not included in existing NERC Reliability Standards. Current practices focus on capacity assessments to evaluate whether sufficient power is available to supply the BPS at peak demand; however, an analysis of energy sufficiency is required to effectively identify BES risks because of the changing resource mix, the increasing volatility of demand, and the interconnected nature of the electric power system (with external supply chains, e.g., natural gas). The *2021 ERO Reliability Risk Priorities Report* (produced by the Reliability Issues Steering Committee) and the *Ensuring Energy Adequacy with Energy-Constrained Resources* whitepaper identified these issues as significant risks to reliability for which solutions to evaluate and mitigate are required. Through a gap analysis of NERC

[8] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Requested information
Reliability Standards and a survey of industry stakeholders, the NERC ERATF more specifically identified the energy-related risks that need to be addressed through the Standards development process. Refer to the ERATF Technical Justification document (Appendix A) for additional information and a more detailed description of the justification. The following [Reliability and Security Guidelines (available at nerc.com)](#) and technical reference documents can serve as guides to develop standards by expanding upon the work of the EGWG to energy assurance standards: • Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis • Reliability Guideline: Generating Unit Winter Weather Readiness • Reliability Guideline: Gas and Electrical Operational Coordination Considerations • Data Collection: Approaches for Probabilistic Assessments • 2020 Probabilistic: Regional Risk Scenarios Sensitivity Case • Probabilistic Adequacy and Measures Report Additionally, the ERATF, Probabilistic Assessment Working Group (PAWG), Reliability Assessment Subcommittee (RAS), and other committees as well as their work can be consulted to facilitate the development of standards requirements.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
It is not the ERATF's intention to require specific solutions to the energy-related issues identified in the assessments. This SAR is intended to propose modifications to NERC's suite of Reliability Standards to require that responsible entities further evaluate risks related to energy availability. In addition, the SAR proposes revisions to Reliability Standards that would require responsible entities to create Corrective Action Plans, Operating Plans, or other mitigating actions to address risks related to energy availability. Using a performance-based approach would allow entities to take local, state, and regional needs, as well as federal regulations and other factors as appropriate into consideration. The costs associated with this assessment are expected to be comparable to those associated with the responsible entity's activities to evaluate and address potential reliability risks to the System. The cost impact is unknown and will be considered during drafting team meetings.
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 characteristics of the BES facilities impacted by this project include: fuel type, delivery logistics (e.g., the ability to access additional fuel, sufficient road and rail networks, barges for waterway-based plants, liquefied natural gas deliveries), design, construction, and operational characteristics, etc.
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):
Primary: Planning Coordinator and Resource Planner. Impacted: Reliability Coordinator, Distribution Provider, Balancing Authority, Transmission Operator, Transmission Owner, Generator Operator, Transmission Service Provider, Transmission Planner, and Generator Owner.
Do you know of any consensus building activities[9] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The ERATF's SAR development process is a consensus building activity and includes input from its members and observers. Previous drafts of the SAR have been presented to and commented on by the Reliability and Security Technical Committee and the Member Representatives Committee members. Those comments are incorporated into the updated SAR. On February 16, 2022, the ERATF conducted an industry workshop that outlined the challenges and considerations concerning solutions for performing energy reliability assessments. On May 19, 2022, the ERATF conducted a follow up industry webinar to provide an update on how the SAR comments have been addressed.
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)?
Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1, Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination and work to coordinate with any further projects that might impact this effort: consider the impact to the TPL, EOP and TOP standards.
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.
Three reliability guidelines and three reference documents have been published in recent years that provide valuable tools for industry to assess and manage energy risks, particularly risks related to fuel assurance. However, the continued reoccurrence of extreme events and resulting impacts on fuel and energy supplies have demonstrated that Reliability Standard(s) are needed to provide consistency across the industry in performing energy reliability assessments and mitigating identified reliability risks. Reliability and Security Guidelines (nerc.com) • Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis • Reliability Guideline: Generating Unit Winter Weather Readiness • Reliability Guideline: Gas and Electrical Operational Coordination Considerations Probabilistic Assessment Working Group (PAWG) (nerc.com) • Data Collection: Approaches for Probabilistic Assessments

[9] 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
• 2020 Probabilistic: Regional Risk Scenarios Sensitivity Case • Probabilistic Adequacy and Measures Report

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
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to	yes

Market Interface Principles	
access commercially non-sensitive information that is required for compliance with reliability standards.	

Identified Existing or Potential Regional or Interconnection Variances	
Region(s)/ Interconnection	Explanation
e.g., NPCC	

For Use by NERC Only

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

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Authorization Request (SAR)

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

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

Requested information			
SAR Title:	Energy Assessments with Energy– Constrained Resources in the Planning Time Horizon		
Date Submitted:	~~June 8, 2022~~ Revised on December 6, 2022		
SAR Requester			
Name:	Chair Peter Brandien on behalf of the Energy Reliability Assessment Task Force (ERATF)		
Organization:	~~The ERATF of the Reliability and Security Technical Committee (RSTC)~~ Revised by Project 2022-03 SAR DT		
Telephone:	(413) 535-4022	Email:	pbrandien@iso-ne.com
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?):			
Unassured deliverability of fuel supplies, coincident with inconsistent output from variable renewable energy resources and volatility in forecasted load, can result in insufficient amounts of energy available from the BES to serve electrical demand and ensure the reliable operation of the BES throughout each hour of the time period being evaluated[1]. Historically, analyses of energy available to the BES focused on capacity reserve levels across peak-demand time periods. Generating resources and the requisite fuel were assumed available. This was a logical assumption in the past as fuel availability was assured with either firm fuel contracts (commodity plus transportation capacity), or on-site storage (e.g., oil, coal, reservoir-based hydro), or required			

[1] The industry need is described in the *Ensuring Energy Adequacy with Energy-Constrained Resources* white paper, presented to the RSTC, December 2020.

Requested information
periodic and predictable fuel replacement (e.g., nuclear). The availability of dispatchable generation with diverse fuel types promoted flexibility in providing energy for the BES should one fuel type become unavailable. Reserve margins are planned so that deficiency in capacity to meet daily peak demand (Loss of Load Expectation {LOLE}) did not exceed one day-in-ten-years. LOLE is calculated from probabilistic analysis, typically using generating unit forced outage rates based on random equipment failures derived from its historic performance. The targeted level of one event every ten years is traditionally based on daily peaks (rather than hourly energy obligations). Additional insights can be gained through these methods by calculating Loss-of-Load-Hours (LOLH) and expected unserved energy (EUE) based on the mean-time-to-repair (MTTR) unit averages. Today, the transition to include more just-in-time energy ~~from coal and nuclear generation to wind, solar, natural gas (with and without oil back up), distributed energy resources, and hybrid (renewables plus energy storage)~~ resources is creating a more complex scenario and highlighting the need for energy assurance. Installed generating capacity analysis alone is not sufficient to ensure a reliable supply of energy for the BES. The proliferation of intermittent renewable generation in the resource mix increases the importance of having precisely controllable resources with sufficient fuel available, ready to respond when needed. The increasing prevalence of distribution-level resources and flexible load programs also introduces added volatility into energy forecasts, further complicating energy reliability assessments. Supply intermittency and demand volatility both require the dispatchable generation fleet to be available and flexible enough to respond when called upon. These factors can also lead to unexpected and unstudied energy issues in non-peak hours, a risk that would not be identified by traditional analyses focused on capacity reserve margins across peak demand periods. The transition to more intermittent resources is increasing the reliance on natural gas as the fuel needed for dispatchable resources that can promote energy assurance; however, uncertainty is still an issue if the natural gas-fueled resources are subject to fuel curtailment or interruption (by virtue of fuel acquisition contracts) during peak fuel demands which often correspond with winter-peak electric demands. Additionally, the design of natural gas pipeline systems and the availability of back-up natural gas feeders can impact individual generators and the BES under pipeline disruption scenarios. The intermittency of renewable generation, demand volatility, the need for sufficient flexibility from balancing generation resources, and the potential for natural gas supply interruptions all combine to highlight the need for energy reliability assessments that analyze all hours of a given study period rather than just across the peak hours. Energy assurance and fuel assurance risks are becoming more apparent as extreme weather has resulted in energy deficits (as opposed to capacity deficits) in recent years. During the past 10 years, multiple extreme events that have jeopardized the BES.

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Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
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Project Scope (Define the parameters of the proposed project):
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Requested information
* Impact of energy storage resources. * Transmission capacity and deliverability to the load centers, including imports. * Correlated impact of weather and other significant events on load and generation[7]. * ~~Extreme weather~~Low probability/high impact weather events. • Energy reliability assessments should be required to: ▪ ~~Include an evaluation of the unique characteristics of variable resources and their impact(s) on non-variable resources (probabilistically).~~ ▪ Be coordinated between areas to synchronize interchange assumptions. ▪ Be conducted on a clearly defined periodic basis and performed in each of the NERC defined planning time horizons. ▪ Be periodically validated and updated, and updated when changes to assumptions and input data nullifies an existing assessment. o ~~Be conducted on a clearly defined periodic basis and performed in each of the NERC defined[8] planning time horizons.~~ o ~~Be periodically validated and updated, and updated when changes to assumptions and input data nullifies an existing assessment.~~ • For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Alternatively~~Instead~~, the standard would require each entity ~~could will~~ to establish and document criteria as part of complying with the Standard.~~.~~ The predefined criteria may be set specifically within the Standard or established and documented by each applicable entity as part of complying with the Standard. • When predefined criteria are not met, ~~require~~ the responsible entity shall develop ~~development of~~ the Corrective Action Plans, Operating Plans or other mitigating actions. • ~~Coordinate with the drafting team that is working on the "*Energy Assessments with Energy-Constrained Resources in the Operations and Operations Planning Time Horizons*" SAR.~~ • Coordinate with the NERC Electric-Gas Working Group, the North American Energy Standards Board, ~~and~~ the *Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination* drafting team and other groups to minimize duplication of efforts and ensure that non-conflicting requirements are developed.

[7] For example, cascading series of issues including an extreme cold weather event across a significant portion of the NERC footprint, multiple forced outages early in the morning (when there is a lack of solar resources), and inadequate availability of natural gas. A wide area impact makes depending on imports less available.
~~[8] https://www.nerc.com/files/glossary_of_terms.pdf~~

Requested information
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[9] 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
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The characteristics of the BES facilities impacted by this project include: fuel type, delivery logistics (e.g., the ability to access additional fuel, sufficient road and rail networks, barges for waterway-based plants, liquefied natural gas deliveries), design, construction, and operational characteristics, etc.
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):
Primary: Planning Coordinator and Resource Planner. Impacted: Reliability Coordinator, Distribution Provider, Balancing Authority, Transmission Operator, Transmission Owner, Generator Operator, Transmission Service Provider, Transmission Planner, and Generator Owner.
Do you know of any consensus building activities[10] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
The ERATF's SAR development process is a consensus building activity and includes input from its members and observers. Previous drafts of the SAR have been presented to and commented on by the Reliability and Security Technical Committee and the Member Representatives Committee members. Those comments are incorporated into the updated SAR. On February 16, 2022, the ERATF conducted an industry workshop that outlined the challenges and considerations concerning solutions for performing energy reliability assessments. On May 19, 2022, the ERATF conducted a follow up industry webinar to provide an update on how the SAR comments have been addressed.
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)?

[10] 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
Project 2022-02 Modifications to TPL-001-5.1 and MOD-032-1, Project 2021-07 Extreme Cold Weather Grid Operations, Preparedness, and Coordination and work to coordinate with any further projects that might impact this effort:~~;~~ consider the impact to the TPL, EOP and TOP standards.
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.
Three reliability guidelines and three reference documents have been published in recent years that provide valuable tools for industry to assess and manage energy risks, particularly risks related to fuel assurance. However, the continued reoccurrence of extreme events and resulting impacts on fuel and energy supplies have demonstrated that Reliability Standard(s) are needed to provide consistency across the industry in performing energy reliability assessments and mitigating identified reliability risks. Reliability and Security Guidelines (nerc.com) • Reliability Guideline: Fuel Assurance and Fuel-Related Reliability Risk Analysis • Reliability Guideline: Generating Unit Winter Weather Readiness • Reliability Guideline: Gas and Electrical Operational Coordination Considerations Probabilistic Assessment Working Group (PAWG) (nerc.com) • Data Collection: Approaches for Probabilistic Assessments • 2020 Probabilistic: Regional Risk Scenarios Sensitivity Case • Probabilistic Adequacy and Measures Report

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.

Reliability Principles	
☐	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 ☐ DRAFT SAR approved for posting by the SC	☐ Final SAR endorsed by the SC ☐ SAR assigned a Standards Project by NERC ☐ SAR denied or proposed as Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template
3	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
4	February 25, 2020	Standards Information Staff	Updated template footer

Standard Development Timeline

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

Description of Current Draft

This is the first draft of the proposed standard for an informal comment period.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	January 25, 2023
SAR posted for comment	June 22, 2022 – July 21, 2022

Anticipated Actions	Date
16-day informal comment period	September 13, 2023 – September 28, 2023
45-day formal or informal comment period with ballot	November 2023 – January 2024
XX-day formal or informal comment period with additional ballot	TBD
XX-day final ballot	TBD
Board adoption	TBD

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

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

Term(s):

Energy Reliability Assessment (ERA): Evaluation of the resources that supply electrical energy and ancillary services for the BPS to reliably meet the expected demand during the associated time period. ERAs account for impact of actions that occur in each iteration on all subsequent iterations, including the depletion and replenishment of finite upstream resources (e.g., fuel).

Near-Term Operational Planning Energy Reliability Assessment (OPERA): An Energy Reliability Assessment (ERA) performed for a short period of time (e.g., no more than six weeks), starting in the current operating day or next day, to be defined by the entity performing the study based on regionally specific requirements.

Study Period: The time period between the start and end of an Energy Reliability Assessment, typically assigned start and end dates, but can be more general for longer lead-time studies.

Study Frequency: The time period between when Energy Reliability Assessments are performed. This can be a prescribed number of days/weeks/months/etc. (e.g., every Monday or every month).

Study Temporal Resolution: The duration of or between each time step modeled in a study. The temporal resolution is the degree of detail with respect to time.

A. Introduction

1. **Title:** **Energy Reliability Assessments**
2. **Number:** **TOP-0XX-X**
3. **Purpose:**
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Reliability Coordinator

B. Requirements and Measures

R1. Each Balancing Authority shall develop, document, and maintain a Reliability Coordinator-reviewed Near-Term Operations Planning Energy Reliability Assessments (OPERA) process. The Near-Term OPERA shall:

1.1. Have a documented Near-Term OPERA Study Frequency, Study Duration, and Study Temporal Resolution with a corresponding rationale for each selection.

1.1.1. The Near-Term OPERA study period will begin within 48 hours following the completion of each assessment.

1.1.2. The maximum Study Frequency will be set such that the time period covered by the current assessment must extend into the time period covered by the future/prompt and assessment and will be performed at least monthly.

1.1.3. The maximum Study Temporal Resolution must be 1 hour.

1.1.4. The Study Duration shall be no less than 7 days.

1.2. The Near-Term OPERA shall use a base case that includes:

1.2.1. Expected demand including demand side management and demand response;

1.2.2. Expected generator capability considering known constraints (e.g., availability and flexibility, fuel supply and inventory concerns, fuel switching capabilities, and environmental constraints ;

1.2.3. Expected transmission usage and coordinated and agreed upon transfers;

1.2.4. Expected generation and transmission outages; and

1.2.5. Expected energy storage capability

R2. Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed Near-Term OPERA scenarios or a method of scenario development.

2.1. The Near-Term OPERA scenarios developed shall include:

2.1.1. The scenarios listed in Table 1; and

2.1.2. Scenarios with a likely risk of occurring within the horizon which may include seasonally appropriate historical events, generation specific fuel or energy contingency scenarios, and weather events that are projected in the Near-Term OPERA horizon.

2.2. All Near-Term OPERA scenarios developed in R2.1 shall have documented criteria which specify when implementing an Operating Process is required.

R3. The Balancing Authority shall submit for review the Near-Term OPERA process and scenarios to the Reliability Coordinator annually on a mutually-agreed upon schedule. [Violation Risk Factor:] [Time Horizon: Operations Planning]

R4. Within 30 calendar days of receipt, the Reliability Coordinator shall:

4.1. Review each submitted Near-Term OPERA process and scenarios on the basis of compatibility with other Balancing Authorities' Near-Term OPERA process and scenarios;

4.2. Review each submitted Near-Term OPERA process and scenarios for coordination to avoid risks to Wide Area reliability; and

4.3. Notify each Balancing Authority of the results of its review, specifying any time frame for resubmittal of its Near-Term OPERA process and scenarios if revisions are identified.

R5. Each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R4 and resubmit its Operating Process(s) and scenarios to its Reliability Coordinator within 30 calendar days of receipt.

R6. Each Balancing Authority shall perform Near-Term OPERA according to processes documented in R1 and scenarios documented in R2.

6.1. The Balancing Authority shall notify its Reliability Coordinator within 24 hours when Near-Term OPERA results require the implementation of an Operating Process(es).

6.2. Results of the Near-Term OPERA and scenarios shall be provided to the Reliability Coordinator upon request.

R7. Each Balancing Authority shall develop and maintain one or more Reliability Coordinator-reviewed Operating Process(s) to mitigate forecasted Energy Emergencies within its Balancing Authority Area. The Operating Process(s) shall include the following, as applicable: [Violation Risk Factor:] [Time Horizon: Operations Planning, Long-term Planning]

7.1. Roles and responsibilities for activating the Operating Process(s);

7.2. Processes to reduce the probability of forecasted Emergencies including but not limited to:

- Updated frequency of performing a Near-Term OPERA to monitor if an Energy Emergency Alert continues to be forecasted or forecasted conditions worsen;
- Notification to its Reliability Coordinator, to include the conditions for the forecasted Energy Emergency;
- Identify when to request an Energy Emergency Alert.;
- Managing generating resources in its Balancing Authority Area to address:
  - capability and availability;
  - fuel supply and inventory concerns;
  - fuel switching capabilities; and
  - environmental constraints.
- Public appeals for voluntary Load reductions;
- Requests to government agencies to implement their programs to achieve necessary energy reductions;
- Reduction of internal utility energy use;
- Use of Interruptible Load, curtailable Load and demand response;

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

7.2.2. Provisions to determine reliability impacts of:

- cold weather conditions; and
- extreme weather conditions.

R8. The Balancing Authority shall submit for review the Operating Process(s) to mitigate operating Emergencies to the Reliability Coordinator annually on a mutually agreed-upon schedule. [Violation Risk Factor:] [Time Horizon: Operations Planning]

R9. Within 30 calendar days of receipt, the Reliability Coordinator shall:

9.1. Review each submitted Operating Process(s) on the basis of compatibility with other Balancing Authorities' Operating Process(s);

9.2. Notify each Balancing Authority of the results of its review, specifying any time frame for resubmittal of its Operating Process(s) if revisions are identified.

R10. Each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R7 and resubmit its Operating Process (s) to its Reliability Coordinator within 30 calendar days of receipt.

R11. Each Balancing Authority shall implement one or more Reliability Coordinator-reviewed Operating Process(s) when a Near-Term OPERA forecasts an Energy Emergency Alert according to Table 1 or as specified for scenarios provided to the Reliability Coordinator according to R2.

R12. Each Reliability Coordinator that receives a forecasted Emergency notification from a Balancing Authority within its Reliability Coordinator Area shall notify, within 24 hours from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. [Violation Risk Factor:] [Time Horizon: Operations Planning]

Table 1. Near-Term OPERA Scenarios

Scenario	Demand Forecast	Contingency Event	If EEA 2[5] is forecasted, Operating Process(s) is Required	If EEA 3[5]is forecasted, Operating Process(s) is Required
Base Case	Normal System Forecast	None	Yes	Yes
High Demand	High Demand Forecast[4]	None	Yes	Yes
Base Case with Energy Contingency	Normal System Forecast	Loss of the largest single energy supply resource from the base case for the duration of the study period[1].	No	Yes
High Demand with Energy Contingency	High Demand Forecast[4]	Loss of the largest single energy supply resource from the base case for the duration of the study period[2].	No	Yes
Base Case with Fuel Contingency	Base Case Forecast	Fuel supply interruption that results in the loss of at least 50% of the largest subset of supply resources sharing a common fuel supply[3] (i.e., all generators on a specific segment of a pipeline or multiple stations with a common fuel source) for the duration of the study period.	No	Yes
High Demand with Fuel Contingency	High Demand Forecast[4]	Fuel supply interruption that results in the loss of at least 50% of the largest subset of supply	No	Yes

[1] This can be a generator or a transmission facility that results in the loss of supply. This is not a widespread outage of multiple resources due to a common extreme weather event.
[2] This can be a generator or a transmission facility that results in the loss of supply. This is not a widespread outage of multiple resources due to a common extreme weather event.
[3] Generators with common fuel supply are all generators on a specific segment of a pipeline or multiple stations with a common fuel source. The fuel source should include pipelines, suppliers of consumable fuels, and variable sources like solar and wind energy.
[4] High demand forecast should be coupled with the associated weather, but leaving solar and wind as modeled in the base case. Examples include 90:10 weather and load forecast or similar weather and load forecast error scenario.
[5] Energy Emergency Alert conditions are defined in EOP-011 Attachment 1.

		resources sharing a common fuel supply[3] for the duration of the study period.		

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Unofficial Comment Form

Project 2022-03 Energy Assurance with Energy-Constrained Resources | TOP-0XX-X

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2022-03 Energy Assurance with Energy-Constrained Resources | TOP-0XX-X** by **8 p.m. Eastern, Thursday, October 5, 2023.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Dominique Love (via email), or at 404-217-7578.

Background Information

This project will enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and when predefined criteria are not met, develop Corrective Action Plan(s), Operating Plans, or other mitigating actions to address identified risks. Energy reliability assessments evaluate energy assurance across the operations and planning time horizons by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.

This project has two assigned Standard Authorization Requests (SARs) with the focus of this informal comment period based on the Operations and Operations Planning Time Horizons SAR. The proposed Standard language outlines the process for the Near-Term Operational Planning Energy Reliability Assessment (OPERA). The Standard Drafting Team (SDT) intends on creating a Seasonal OPERA to be incorporated along with Near-Term OPERA at a later date.

The SDT is conducting an informal comment period to solicit feedback on proposed new definitions and new TOP-0XX Standard language below that addresses:

- New Definition for Energy Reliability Assessment (ERA)
- New Definition for Near-Term Operational Planning Energy Reliability Assessment (OPERA)
- New Definition for Study Period
- New Definition for Study Frequency
- New Definition for Study Temporal Resolution
- New TOP-0XX-X Standard

Definitions:

1. The Energy Reliability Assessment (ERA) definitions are intended to support the Near-Term OPERA which is discussed in this comment period and additional ERAs to be developed by this Standard Drafting Team (SDT). Are the definitions clear and understandable? If not, how would you suggest improving them?

   ☐ Yes
   ☐ No

   Comments:

TOP-0XX-X Standard – Energy Reliability Assessments

Requirement 1

2. Energy Reliability Assessment Temporal Requirements (1): The SDT proposes several temporal parameters for the regular performance of Near-Term Operational Planning Energy Reliability Assessments (OPERA). The first is the requirement that the study begin within 48 hours following the completion of each assessment. The intent is that the first hour of the Near-Term OPERA would not be too far in the future, ensuring the starting point is based upon current information. Is using a starting point of no more than 48 hours in the future appropriate? If not, please comment with alternate language and explanation of recommended changes.

   ☐ Yes
   ☐ No

   Comments:

3. Energy Reliability Assessment Temporal Requirements (2): The minimum Study Frequency (how often a Near-Term OPERA is performed) is set to monthly to ensure that results do not become outdated. The Study Frequency is also a function of study duration (how many days/hours the Near-Term OPERA looks at). The requirement for Study Frequency to be less than or equal to the study duration ensures that no period of time is uncovered by a Near-Term OPERA. Is the

requirement to perform a Near-Term OPERA no less than monthly, appropriate, or should it be more or less frequent? If more or less frequent, please comment with alternate language.

☐ Appropriate
☐ More frequent
☐ Less frequent

Comments:

4. Energy Reliability Assessment: R1.1 and R1.2 are intended to add requirements that outline the elements that should be included in a Near-Term OPERA but allow Balancing Authorities (BA) with different concerns to have flexibility to implement the assessment such that the assessments are useful. Do you agree with the level of specificity in these requirements? If not, would you prefer that the requirements related to this are more or less specific? Additionally, please comment on what requirements should be removed, clarified, or changed.

☐ Appropriately specific
☐ Should be less specific
☐ Should be more specific

Comments:

Requirement 2

5. Near-Term OPERA Scenarios: The SDT is proposing to require the development and analysis of scenarios which have a reasonable risk of occurring through the time-horizon of the Near-Term OPERA. Table 1 includes standard scenarios that shall also be evaluated. These scenarios shall have documented criteria which specify when implementing a mitigation Operating Process solution is required. Do you agree with the language in the requirement? If not, please comment with alternate language and explanation of recommended changes.

☐ Yes
☐ No

Comments:

Requirements 3/4/5

6. Balancing Authority (BA) Requirements: The proposed Requirements 3, 4 and 5 are modeled after Requirements 2, 3 and 4 in EOP-011-2 to ensure that an individual BA's Near-Term OPERA processes are reviewed by the Reliability Coordinator (RC) based on compatibility and inter-dependency with other BA's Near-Term OPERA processes and scenarios, and have the BA address reliability risks identified by the RC. Do you agree that the requirements for the BA to have its processes reviewed by the RC and any RC-identified issues be addressed by the BA are reasonable?

☐ Yes
☐ No

Comments:

Requirement 6

7. Balancing Authority notifies the RC within 24 hours of identified forecasted Energy Emergencies: Once the Near-Term OPERA has been performed, per the RC reviewed Operating Process, R6 requires the BA to notify its RC within 24 hours of any identified forecasted Energy Emergencies. The 24 hours notification to the RC of all forecasted Energy Emergency provides time for the BA to prepare and respond to the forecasted Energy Emergency. Do you agree that the BA must notify the RC within 24 hours? If not, please comment what would be more appropriate and explain why.

☐ Yes
☐ No

Comments:

8. Submit the Near-Term OPERA results to the RC upon request: The requirement to submit the results to the RC upon request is intended to ensure the RC can review the assessment results. This requirement ensures the RC can review the results to verify the processes and scenarios are being implemented and to review any adverse results. Do you agree that the results must be submitted to the RC upon request, for RC review? If not, please comment which would be more accurate and explain why.

☐ Yes
☐ No

Comments:

Requirement 7

9. Operating Process Development: The proposed Requirements 7, 8 and 9 are modeled after Requirements 2, 3 and 4 in EOP-011-2 to ensure that there is a plan developed to respond to deficiencies noted during the performance of a Near-Term OPERA. R7 is intended that Operating Processes would be developed before OPERAs are performed and would be a high-level plan of how a BA would approach a forecasted Energy Emergency, not necessarily a step-by-step process. R7 has required actions listed for consideration that are intended to reduce the risk of Energy Emergencies. As written, the requirement provides a list of optional steps to consider as part of an Operating Process. Should the list of requirements for Operating Processes be optional (as written), be required to be addressed for all BAs (as in EOP-011), or removed from R7 entirely? Please provide additional actions or notes which should not be included in this list as comments.

☐ The listed actions should be addressed by all BAs (as in EOP-011)
☐ The listed actions should be options (as written)
☐ The listed actions should not be part of the Standard

Comments:

10. Operating Process Development: The requirement is intended to ensure that there is a plan developed to respond to deficiencies noted during the performance of a Near-Term OPERA. While there are multiple possible types of plans that could be developed (e.g., Operating Plan, Operating Process, Operating Procedure, Corrective Action Plan), the most relevant defined term for responding to a forecasted Energy Emergency is Operating Process. Do you agree with the correct type of plan being an Operating Process? If not, please comment which would be more accurate and explain why.

☐ Yes
☐ No

Comments:

Requirements 8/9/10

11. Address Risks Identified in the Review: R8 is intended to provide RCs with information that is needed to ensure that the plans address the reliability of the system. R9 is needed to ensure that any risk identified by the RC in R7 is mitigated by the BA. The SDT proposes that the BA addresses the risk in its Operating Plan and resubmits it to its RC. R10 requires the BA to revise the Operating Process that was previously reviewed by the RC and found to require modifications. Do you agree with the language in the requirements including the proposed timeframes? If not, please provide updated language in your comment as well as a basis for the recommendation.

☐ Yes
☐ No

Comments:

Requirements 11/12

12. Implementation of Operating Process: R11 is a follow-up from R7, where the BA is now implementing the Operating Process that was previously developed. R12 requires the RC to ensure quick dissemination of critical information to a list of entities which can take appropriate actions to respond to the forecasted Energy Emergency. Does the proposed language clearly outline the responsibilities of the BA and RC in the event of a forecasted Energy Emergency? Is the 24-hour notification window feasible and appropriate for the types of emergency situations that might arise? Please provide any other comments about the language in Requirements 11 and 12.

☐ Yes
☐ No

Comments:

13. Provide any additional comments for the SDT to consider, if desired.

Comments:

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources | TOP-0XX-X

Informal Comment Period Open through October 5, 2023

Now Available

An informal comment period for **Project 2022-03 Energy Assurance with Energy-Constrained Resources | TOP-0XX-X** is open through **8 p.m. Eastern, Thursday, October 5, 2023**.

Commenting

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

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

Next Steps

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

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

For more information or assistance, contact Standards Developer, Dominique Love (via email) or at 404-217-7578. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources observer list” in the Description Box.

RELIABILITY CORPORATION

404-446-2560 | www.nerc.com

Comment Report

Project Name: 2022-03 Energy Assurance with Energy-Constrained Resources | TOP-0XX-X

Comment Period Start Date: 9/13/2023

Comment Period End Date: 10/5/2023

Associated Ballots:

There were 29 sets of responses, including comments from approximately 115 different people from approximately 84 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The Energy Reliability Assessment (ERA) definitions are intended to support the Near-Term OPERA which is discussed in this comment period and additional ERAs to be developed by this Standard Drafting Team (SDT). Are the definitions clear and understandable? If not, how would you suggest improving them?

2. Energy Reliability Assessment Temporal Requirements (1): The SDT proposes several temporal parameters for the regular performance of Near-Term Operational Planning Energy Reliability Assessments (OPERA). The first is the requirement that the study begin within 48 hours following the completion of each assessment. The intent is that the first hour of the Near-Term OPERA would not be too far in the future, ensuring the starting point is based upon current information. Is using a starting point of no more than 48 hours in the future appropriate? If not, please comment with alternate language and explanation of recommended changes.

3. Energy Reliability Assessment Temporal Requirements (2): The minimum Study Frequency (how often a Near-Term OPERA is performed) is set to monthly to ensure that results do not become outdated. The Study Frequency is also a function of study duration (how many days/hours the Near-Term OPERA looks at). The requirement for Study Frequency to be less than or equal to the study duration ensures that no period of time is uncovered by a Near-Term OPERA. Is the requirement to perform a Near-Term OPERA no less than monthly, appropriate, or should it be more or less frequent? If more or less frequent, please comment with alternate language.

4. Energy Reliability Assessment: R1.1 and R1.2 are intended to add requirements that outline the elements that should be included in a Near-Term OPERA but allow Balancing Authorities (BA) with different concerns to have flexibility to implement the assessment such that the assessments are useful. Do you agree with the level of specificity in these requirements? If not, would you prefer that the requirements related to this are more or less specific? Additionally, please comment on what requirements should be removed, clarified, or changed.

5. Near-Term OPERA Scenarios: The SDT is proposing to require the development and analysis of scenarios which have a reasonable risk of occurring through the time-horizon of the Near-Term OPERA. Table 1 includes standard scenarios that shall also be evaluated. These scenarios shall have documented criteria which specify when implementing a mitigation Operating Process solution is required. Do you agree with the language in the requirement? If not, please comment with alternate language and explanation of recommended changes.

6. Balancing Authority (BA) Requirements: The proposed Requirements 3, 4 and 5 are modeled after Requirements 2, 3 and 4 in EOP-011-2 to ensure that an individual BA's Near-Term OPERA processes are reviewed by the Reliability Coordinator (RC) based on compatibility and inter-dependency with other BA's Near-Term OPERA processes and scenarios, and have the BA address reliability risks identified by the RC. Do you agree that the requirements for the BA to have its processes reviewed by the RC and any RC-identified issues be addressed by the BA are reasonable?

7. Balancing Authority notifies the RC within 24 hours of identified forecasted Energy Emergencies: Once the Near-Term OPERA has been performed, per the RC reviewed Operating Process, R6 requires the BA to notify its RC within 24 hours of any identified forecasted Energy Emergencies. The 24 hours notification to the RC of all forecasted Energy Emergency provides time for the BA to prepare and respond to the forecasted Energy Emergency. Do you agree that the BA must notify the RC within 24 hours? If not, please comment what would be more appropriate and explain why.

8. Submit the Near-Term OPERA results to the RC upon request: The requirement to submit the results to the RC upon request is intended to ensure the RC can review the assessment results. This requirement ensures the RC can review the results to verify the processes and

scenarios are being implemented and to review any adverse results. Do you agree that the results must be submitted to the RC upon request, for RC review? If not, please comment which would be more accurate and explain why.

9. Operating Process Development: The proposed Requirements 7, 8 and 9 are modeled after Requirements 2, 3 and 4 in EOP-011-2 to ensure that there is a plan developed to respond to deficiencies noted during the performance of a Near-Term OPERA. R7 is intended that Operating Processes would be developed before OPERAs are performed and would be a high-level plan of how a BA would approach a forecasted Energy Emergency, not necessarily a step-by-step process. R7 has required actions listed for consideration that are intended to reduce the risk of Energy Emergencies. As written, the requirement provides a list of optional steps to consider as part of an Operating Process. Should the list of requirements for Operating Processes be optional (as written), be required to be addressed for all BAs (as in EOP-011), or removed from R7 entirely? Please provide additional actions or notes which should not be included in this list as comments.

10. Operating Process Development: The requirement is intended to ensure that there is a plan developed to respond to deficiencies noted during the performance of a Near-Term OPERA. While there are multiple possible types of plans that could be developed (e.g., Operating Plan, Operating Process, Operating Procedure, Corrective Action Plan), the most relevant defined term for responding to a forecasted Energy Emergency is Operating Process. Do you agree with the correct type of plan being an Operating Process? If not, please comment which would be more accurate and explain why.

11. Address Risks Identified in the Review: R8 is intended to provide RCs with information that is needed to ensure that the plans address the reliability of the system. R9 is needed to ensure that any risk identified by the RC in R7 is mitigated by the BA. The SDT proposes that the BA addresses the risk in its Operating Plan and resubmits it to its RC. R10 requires the BA to revise the Operating Process that was previously reviewed by the RC and found to require modifications. Do you agree with the language in the requirements including the proposed timeframes? If not, please provide updated language in your comment as well as a basis for the recommendation.

12. Implementation of Operating Process: R11 is a follow-up from R7, where the BA is now implementing the Operating Process that was previously developed. R12 requires the RC to ensure quick dissemination of critical information to a list of entities which can take appropriate actions to respond to the forecasted Energy Emergency. Does the proposed language clearly outline the responsibilities of the BA and RC in the event of a forecasted Energy Emergency? Is the 24-hour notification window feasible and appropriate for the types of emergency situations that might arise? Please provide any other comments about the language in Requirements 11 and 12.

13. Provide any additional comments for the SDT 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
Independent Electricity System Operator	Harishkumar Subramani Vijay Kumar	2		IRC SRC	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Elizabeth Davis	PJM	2	MRO
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Charles Yeung	SPP	2	MRO
					Ali Miremadi	CAISO	2	WECC
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
					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
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jasmine Morris	Southern Maryland Electric Cooperative	3	RF
MRO	Kendra Buesgens	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Jamie Monette	Allete - Minnesota Power, Inc.	1	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc.	2	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO

					Shonda McCain	Omaha Public Power District	6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
Southern Company - Southern Company Generation	Leslie Burke	5,6		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
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
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC
Sacramento Municipal Utility District	Tim Kelley	1,3,4,5,6	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
Associated Electric Cooperative, Inc.	Todd Bennett	1,3,5,6		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC

					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Tony Gott	KAMO Electric Cooperative	3	SERC
					Micah Breedlove	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. The Energy Reliability Assessment (ERA) definitions are intended to support the Near-Term OPERA which is discussed in this comment period and additional ERAs to be developed by this Standard Drafting Team (SDT). Are the definitions clear and understandable? If not, how would you suggest improving them?

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

ERA:

Suggest the following for the first sentence of ERA to reflect the current BES definition and pending IBR registration criteria:

*Evaluation of the resources that supply electrical energy and ancillary services for the **BES and NERC registered generation** to reliably meet the expected demand during the associated time period.*

Suggest the following for the last sentence of ERA:

ERAs account for the impact of actions that occur in each time interval on all subsequent time intervals, including unavailability, or depletion and replenishment of finite upstream resources (e.g., fuel, hydro reservoirs, batteries, and wind, among others).

Study Period: Unclear what lead time has to do with it. The study period is simply the future time period that is being studied or assessed. In addition, although this term is used several times in the standard, it is never capitalized.

Study Frequency: The time period between when Energy Reliability Assessments are performed could be confused to mean the time between the end of one and the start of the next. Better to say it is how often an assessment is carried out, e.g. every seven days on a Friday, every 14 days on a Friday, every month on the first Friday, etc.

Recommend the SDT provide a timeline example in the Technical Rationale.

Likes 0	

Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power endorses MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA does not believe definitions are needed for Study Period, Study Frequency or Study Temporal Resolution. BPA suggests that if an hourly study is required, use the term 'hourly' rather than 'temporal'.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
-Please consider whether "BES" should be used instead of BPS for the term Energy Reliability Assessment (ERA).	

-Add “Near-Term” in the Near-Term Operational Planning Energy Reliability Assessment acronym (OPERA) to avoid confusion when seasonal OPERA is implemented. -Change Study Temporal Resolution to “Study Temporal Granularity”. Use of the word resolution implies a CAP.	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	
Answer	No
Document Name	
Comment	
Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
It is not clear for the definition of ERA: does the assessment need to perform every day to cover no more than six weeks or just once in a certain number of days. Please provide examples to clarify the timelines mentioned in R1. MH also supports MRO NSRF’s vote and comments for this one.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC	
Answer	No
Document Name	
Comment	

Aside from the definition of an Energy Reliability Assessment, GSOC does not believe that the proposed definitions are either clear or necessary. Moreover, they do not provide regional flexibility that would likely be necessary to provide meaningful results.	
Likes 0	
Dislikes 0	
Response	
Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company supports the EEI comments and does **not** believe that the proposed definitions are necessary or add reliability benefits.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	
Suggested Revision to remove six weeks in the Near Term OPERA definition: **Near-Term Operational Planning Energy Reliability Assessment (OPERA):** An Energy Reliability Assessment (ERA) performed for a short period of time, starting in the current operating day or next day, to be defined by the entity performing the study based on regionally specific requirements.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	

Ameren agrees with and supports MISO's comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

With the exception of the proposed definition of “Energy Reliability Assessment” (ERA), EEI does not agree that the proposed definitions are necessary or add reliability benefits. The current time frames identified in the NERC Glossary of Terms and in the existing NERC Reliability Standards (see examples below) provide a sufficient framework to adequately describe the desired time periods associated with the proposed ERA. Those existing timeframes, coupled with the existing definitions in NERC’s Glossary of Terms for Operating Process, Operating Plan and Operating Procedures should provide adequate guidance without introducing additional terms that may be unnecessary or unduly prescriptive and thereby could possibly limit needed regional flexibility. For these reasons, the definitions for “Near Term OPERA”, “Study Period”, “Study Frequency”, and “Study Temporal Resolution” should be deleted. However, we do see value in the proposed definition of “Energy Reliability Assessment” but offer the following proposed changes in boldface below:

ERA Definition: Evaluation of the resources that supply electrical energy and ancillary services for the **BES and NERC registered generation** to reliably meet the expected demand during the associated time period. ERAs account for **attribution of these resources which can change over time in the relevant study period (e.g., the depletion and replenishment of fuel and impacts of energy storage devices, including capacity depletion and recharging impacts).**

Example Standards and Glossary References

IRO-017-1

From “Section F” and “Guideline and Technical Basis” –

The official definition of the **Operations Planning Time Horizon** is: “operating and resource plans from **day-ahead up to and including seasonal**.” The SDT equates ’seasonal’ as being up to one year out and that these requirements cover the period from **day-ahead to one year out**. (See IROL-017-1 Technical Rationale, Rationale for Time Horizon, page 7)

TOP-002-5 –

R4—

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

EOP-011-4 –

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**]***

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**]*

NERC Glossary of Terms –

Real Time & Real Time Assessment

Operational Planning Analysis (Next Day)

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	No
Document Name	

Comment

BC Hydro appreciates the opportunity to review and offers the following.

The ERA definition can benefit from additional clarity, as the current draft could be interpreted that the “resources” themselves are evaluated (e.g. what resource types are best). BC Hydro believes it should be on whether we have enough of our existing resources.

Recommend revising the ERA definition to focus on an evaluation of whether the supply is sufficient for demand, and then expand upon what is “supply” and “demand”. Also, if terms already defined in the Glossary such as “demand” are intended to be used, these should be capitalized; alternatively, suggest using different wording to alleviate possible confusion.

Also, in the ERA definition it is not clear what is meant by “impact of actions that occur in each iteration on all subsequent iterations”. Please clarify.

In the Near-Term OPERA definition, does the “short period of time” wording pertain to the time to carry out the ERA or the time period for which an ERA is performed. Also, the Near-Term OPERA uses the term “study” – it is unclear what is meant by study (is it the ERA or any study)

The Study Period definition appears to imply that Study Period is the time needed to carry out the assessment. Please confirm whether this is the intended interpretation.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	No
Document Name	
Comment	
Comments: The ISO/RTO Council (IRC) Standards Review Committee (SRC) suggests the following to improve the clarity of the proposed definitions: • ERA: Add the following for the last sentence: “ERAs account for the impact of actions that occur in each time interval on all subsequent time intervals, including unavailability, or depletion and replenishment of finite upstream resources (e.g., fuel, hydro reservoirs, batteries, and wind, among others)”. • Study Period: It is not clear what lead time has to do with the study period. In addition, “study period” is never capitalized when it is used in the standard. The SRC recommends that the term be capitalized when used. • Study Frequency: The phrase “The time period between when ERAs are performed” could be confused to mean the time between the end of one ERA and the start of the next ERA. We suggest it clarifying this definition to indicate that it refers to the frequency with which an assessment is carried out, e.g. every seven days on a Friday, every 14 days on a Friday, every month on the first Friday, etc. The ISO/RTO Council (IRC) Standards Review Committee (SRC) suggests the following to improve the clarity of the proposed definitions: • ERA: Add the following for the last sentence: “ERAs account for the impact of actions that occur in each time interval on all subsequent time intervals, including unavailability, or depletion and replenishment of finite upstream resources (e.g., fuel, hydro reservoirs, batteries, and wind, among others)”. • Study Period: It is not clear what lead time has to do with the study period. In addition, “study period” is never capitalized when it is used in the standard. The SRC recommends that the term be capitalized when used. • Study Frequency: The phrase “The time period between when ERAs are performed” could be confused to mean the time between the end of one ERA and the start of the next ERA. We suggest it clarifying this definition to indicate that it refers to the frequency with which an assessment is carried out, e.g. every seven days on a Friday, every 14 days on a Friday, every month on the first Friday, etc.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
In general, PAC supports some of the comments submitted by the MRO. TOP-0XX-X is a very complicated and broad standard to be able to comment on with so little time for RC, area and entity interactions discussions. PAC believes that as written, TOP-0XX-X is too prescriptive and too duplicative of current standard requirements to make specific comments at this time. The drafting team needs to address the duplicative activities and allow time for more RC and regional discussions.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No

Document Name	
Comment	
PNM Resourcess aggrees with EEI that the terms as “Study Period”, Study Frequency” or “Study Temporal Resolution” do not need to be defined as a NERC Glossary Term. For purposes of a NERC Reliability Standard, study periods, study frequency and study resolution/degree of detail should be clearly defined in the language of the Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS does not agree that the definitions are clear and understandable. AZPS believes these new definitions, outside of the Energy Reliability Assessment (ERA) definition itself, are not necessary to describe an ERA and do not provide the regional flexibility necessary to produce a meaningful assessment.	
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) and adopts them as its own.	
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 ERA definition uses the acronym “BPS”, yet this acronym is not defined. We assume it to stand for the NERC defined term “Bulk Power System”; however, we recommend spelling it out for clarity.

Likes 0	
Dislikes 0	
Response	

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #1. In addition, Evergy believes that the EEI suggested edits to this draft would make the standard requirements flexible enough to cover both near-term and seasonal operational planning assessments effectively. Given that the drafting team has planned to draft separate language related to seasonal operational assessments, Evergy recommends the drafting team assess to what extent these proposed edits could meet that goal as well.

Likes 0	
Dislikes 0	
Response	

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD

Answer	No
Document Name	
Comment	

The term should be changed to "Resource Reliability Assessment" as BAs assess not only available energy but also available capacity.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. Energy Reliability Assessment Temporal Requirements (1): The SDT proposes several temporal parameters for the regular performance of Near-Term Operational Planning Energy Reliability Assessments (OPERA). The first is the requirement that the study begin within 48 hours following the completion of each assessment. The intent is that the first hour of the Near-Term OPERA would not be too far in the future, ensuring the starting point is based upon current information. Is using a starting point of no more than 48 hours in the future appropriate? If not, please comment with alternate language and explanation of recommended changes.

Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #2.	
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 proposed language in R1.1.1 is not clear. If the intent is “that the first hour of the Near-Term OPERA would not be too far in the future, ensuring the starting point is based upon current information” then the language should reflect this. As written the actual intent is obfuscated. Based on our interpretation of the language and stated intent of the proposed Requirement 1, we recommend modifying the language in R1.1.1 as follows: “The Study Period should be sufficiently sized so that in conjunction with the Study Frequency, the Study Period for the current Near-Term OPERA will begin no more than 48-hours in the future from the current Operating Day.”	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

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

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

AZPS feels the performance of ERAs should provide regional flexibility and be based on the operational experience of the Balancing Authority to identify when an ERA should be performed and the time frames associated, such that the resultant ERA is meaningful and useful in addressing any potential reliability concerns.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	No
Document Name	

Comment

Requirement R1 is ambiguous on this topic. Requirement R1, part 1.1.1 states that the study period will begin within 48 hours following the completion of each assessment. Study Period is defined on page 2 of the draft standard as the time period between the start and end of an Energy Reliability Assessment, but, as noted in the SRC's response to question 1, the term "study period" is not capitalized in part 1.1.1, so it is unclear if the formal definition is intended to apply. Even if the formal definition is intended to apply, it is unclear whether the definition refers to the start and end dates of the time period analyzed by an Energy Reliability Assessment or the start and end dates of the time when a BA is actively performing the Energy Reliability Assessment. If Study Period is intended to refer to the start and end dates of the time period analyzed by an ERA, the SRC recommends that the definition be revised to read "The time period analyzed by an Energy Reliability Assessment." Meanwhile, R1 refers in several places to a Study Duration, with the capitalization implying that Study Duration is a defined term, but Study Duration does not appear in the list of new or modified defined terms on page 2 of the draft standard or in the NERC Glossary of Terms. It is likewise unclear whether Study Duration is intended to refer to the Study Period or to a different concept. Due to these ambiguities, the SRC is uncertain what would be required to begin within 48 hours of the completion of each assessment and is therefore unable to fully comment on whether the 48-hour period is appropriate. The SRC recommends that the function of the 48-hour period be clarified, and regardless of the intended function, the SRC recommends that the timeframe be extended to 72 hours to allow entities more flexibility in implementing the requirement. The SRC also notes that it is unclear whether the term "study" and the term "assessment" refer to the same thing or different things in R1 and recommends that only one term be used or that both terms be defined in the interest of clarity. Finally, the SRC requests that the phrase "the time period covered by the future/prompt and assessment" in part 1.1.2 be clarified as proposed below. We suggest the following wording changes for the following sub-requirements: o Requirement 1.1.1.: Replace the currently proposed wording with "The Near-Term OPERA must assess a study period that begins no later than 72 hours in the future". o Requirement 1.1.2: Change the currently proposed wording "must extend into the time period covered by the future/prompt and assessment" to "must extend into the time period covered by the next or subsequent assessment".

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	No
Document Name	

Comment

Requirement R1 appears confusing as drafted.

A. R1 requires a Near-Term OPERA process, while the subsequent subparts address the Near-Term OPERA itself. Recommend that "The Near-Term OPERA shall:" be changed to "The process should ensure that the Near-Term OPERA shall:".

B. Part 1.1 requires a documented Study Duration – this is capitalized, however it is not a defined term.

C. The subparts R1.1.1 through R1.1.4 attempt to be prescriptive, however are hard follow. Specifically:

- Subpart 1.1.1 seems to define when a study period begins. First, should study period be capitalized as it is a defined term? Second, is Subpart 1.1.1 intended to mean that the entity has up to 48 hours to start a new Near-Term OPERA from the end of the previous Near-Term OPERA? The survey Question #2 indicates "intent is that the first hour of the Near-Term OPERA would not be too far in the future". This does not seem to align with the definition of Study Period.
- Depending on the intent of the "time period" referenced in Subpart 1.1.2, this potentially conflicts with Subpart 1.1.1.

D. Part 1.2 "The Near-Term OPERA shall use a base case that includes:" should be revised to "Use a base case that includes:" to align with R1 and R1.1 language.

E. The volume of data requirements as implied under Part 1.2 and its Subparts, and the expected associated evidence may be particularly burdensome. BC Hydro recommends that these specifics be moved to a guideline and not be a requirement, as the entity should be able to identify criteria that may be more applicable to the entity versus defining the base case criteria that may not fit all.

F. The use of "Reliability Coordinator-reviewed" language in Requirement R1 appears to establish a requirement for the RC to review the BA Near-Term OPERA process as part of the BA's compliance for R1 ie the BA's process would be found non-compliant per R1 if the RC hadn't reviewed it. As there are specific Requirements for the BA to submit R1 process to the RC in R3, BC Hydro suggests that this is not required and recommends revising R1 wording to remove this language.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No

Document Name	
Comment	

EEI does not support the approach proposed in Requirement R1. This approach is too prescriptive; as such, it interferes with needed regional flexibility. Instead, EEI suggests the adoption of a more simplified approach based on ERA Operating Processes. Such an approach should be based on the operational experience of the Balancing Authority so that the BA can decide when an ERA should be performed and the associated time frames, such that the resulting ERA is meaningful and useful in addressing any potential reliability concerns specific to their regional responsibilities. An ERA Operating Process with the requirement to address the rationale would be sufficient.

EEI offers the following proposed changes to Requirements R1 for consideration:

R1: Each Balancing Authority shall develop, document, and maintain a Reliability Coordinator-reviewed Energy Reliability Assessment (ERA) Operating Process. The ERA Operating Process shall:

1.1. Identify what operational conditions should be met when an ERA is performed; and

1.2. Provide the rationale for how the operational conditions were selected.

1.3. Define how the ERA will be performed for each period of time to be assessed when the operational conditions are met. At a minimum, the ERA Operating Process shall document the methodology for at least two periods of time—namely, next day and seasonal ERAs, including:

1.3.1. The components to be considered in the ERA;

1.3.2. The rationale for the components to be considered in the ERA;

1.3.3. The components to be considered in the ERA that should be varied to provide a broader risk assessment, based on regional operational experience;

1.3.4. The rationale for selection of the components in the ERA that should be varied; and

1.3.5. The entities that should receive the ERA when performed.

Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	

Ameren agrees with and supports MISO's comments.

Likes 0	

Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	

While ISO-NE agrees that a starting hour of no more than 48 hours in the future would be appropriate, ISO-NE believes that each BA should be able to determine its own Near-Term Opera Study Frequency, Study Period, and Study Temporal Resolution with corresponding rationale for each as well as a Base Case for the OPERA Study.

Suggested modification of R1:

R1. Each Balancing Authority shall develop, document, and maintain a Reliability Coordinator-reviewed Near-Term Operations Planning Energy Reliability Assessments (OPERA) process. The Near-Term OPERA shall include:

1.1. A Study Frequency;

1.2. A Study Period;

1.3. A Study Temporal Resolution, and;

1.4. A corresponding rationale for each selection in R1.1 – R1.3.

1.5. A base case that includes:

1.5.1. Forecasted demand including demand side management and demand response;

1.5.2. Expected generator capability considering:

• known constraints;

• availability and flexibility;

• fuel supply and inventory concerns;

• fuel switching capabilities;

• environmental constraints, and;

• energy storage capability.

1.5.3. Expected transmission usage and coordinated and agreed upon transfers with adjacent Balancing Authorities;

1.5.4. Planned generation and transmission outages; and;

1.5.5. Unplanned generation and transmission outages.

Revision details:

Reordered the sub-requirments for clarity.

1.5 Created sub-requirements for the Base case and consolidated the list as needed.

1.5.2 Expanded the list to sub-bullets to encompass generatoir capability considerations.

1.5.3 Added “with adjacent BAs”

1.5.4 Changed Expected to planned ans outages are planned

1.5.5 Added unplanned outages which would take into consideration EFORd outage rates, etc.

ISO-NE will submit a redline version of TOP-0XX-X in the response for Question #13

Likes 0	
Dislikes 0	

Response

Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company supports the EEI comments and does **not** support the approach proposed in Requirement R1

Likes 0	
Dislikes 0	

Response

Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC

Answer	No
Document Name	

Comment

GSOC does not agree with the requirement as written due to it being overly prescriptive and not providing regional flexibility. GSOC is supportive of the alternate language being submitted by Southern Company.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
There needs to be some consideration on holidays & long weekend which is beyond 48 hours. MH also supports MRO NSRF's vote and comments for this one.	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	
Answer	No
Document Name	
Comment	
Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes the temporal parameters language of this requirement is subject to conflict in interpretation. The timeframes need to be better defined. The requirement does not use the capitalized defined term for study period, which may lead to confusion. The starting point of 48 hours in the future is appropriate.	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power endorses MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
The requirement in 1.1.1 is unclear. Is the intent that once one OPERA concludes, the next one begins within 48 hours? It is unclear what “assessment” is referring to. It is also unclear how this relates to the requirement in 1.1.2 about assessments being performed at least monthly. Also, it appears that the requirements are to have a documented process regarding Near-Term OPERA studies, including scenarios that the RC has reviewed. Is there a requirement that the data or studies be sent to the RC or anywhere else? In bilateral/non-organized markets, the assessments envisioned here are performed on an informal basis daily for at least the preschedule day(s). In addition, entities may have their own resource sufficiency/resource adequacy programs or requirements that entail similar evaluations for upcoming time periods such as peak seasons. However, there may or may not be existing requirements to run analysis over a broad spectrum of scenarios even for non-peak months or seasons. Running and retaining the studies and the various scenarios on the timelines listed in the draft standard could take significant resources and time. This effort may be somewhat duplicative of other resource adequacy efforts. NERC should consider whether this requirement and standards are necessary given those other efforts.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	

Comment	
The MRO NSRF believes it is appropriate to require the study period is not too far in the future; however, at 48 hours, it limits entities from starting a study on Friday to cover a Study Period beginning the following Monday. Recommend making it up to **96 hours** in the future. This will allow for analysis performed on Friday to cover the period beginning on Monday. The wording seems awkward. Suggest "The Near-Term OPERA must assess a study period that begins no later than **96 hours** in the future. Re: Part 1.1.2 Should "must extend into the time period covered by the future/prompt and assessment" read "must extend into the time period covered by the next or subsequent assessment" ? **Recommend the SDT provide a timeline example in the Technical Rationale.**	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
While WAPA agrees that 48 hours is a reasonable duration between Near-Term OPERA Study Periods, the Requirement R1, Part 1.1.1 language is confusing, potentially implying that the SDT intends to encourage gaps between Near-Term OPERA Study Periods and when the studies are actually commenced. Instead, the language should be revised to clearly state: ***1.1.1 Consecutive Near-Term OPERA Study Periods shall overlap by at least one hour.***	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	No
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR agrees with the 48 hour time frame for the Near-Term OPERA study period following the completion of each assessment, the use of assessment and study interchangeable in Requirement R1 adds some confusion.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
-For R1.1.1, “Study Period” should be capitalized.	
Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE noticed the following:

• Part 1.1.1. - The term “study period “ should be capitalized as it is a proposed defined term. Part 1.1.1 should also be changed from “will” to “shall” as it is a requirement. Texas RE recommends the SDT clarify what is considered completion of assessment. The SDT may want to consider what occurs during weekends and holidays.

• The SDT could clarify Part 1.1.2 and what the intention around “covered by the future/prompt and assessment and” is.

• Part 1.1.4 “Study Duration” is not defined; is this intended to be Study Period, which is proposed to be defined?

• It would be helpful for the SDT to provide an example timeline for multiple ERAs as there could be several on-going timelines to consider.

• Part 1.2.3 – The terms “expected transmission usage” and “coordinated and agreed upon transfers” could be clarified in order to drive consistency.	
Likes 0	
Dislikes 0	
Response	

3. Energy Reliability Assessment Temporal Requirements (2): The minimum Study Frequency (how often a Near-Term OPERA is performed) is set to monthly to ensure that results do not become outdated. The Study Frequency is also a function of study duration (how many days/hours the Near-Term OPERA looks at). The requirement for Study Frequency to be less than or equal to the study duration ensures that no period of time is uncovered by a Near-Term OPERA. Is the requirement to perform a Near-Term OPERA no less than monthly, appropriate, or should it be more or less frequent? If more or less frequent, please comment with alternate language.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

A minimum two-week frequency seems or appropriate, or at least a full assessment at least monthly, with incremental assessments more frequently ?

Regarding Study Frequency: The time period between when Energy Reliability Assessments are performed could be confused to mean the time between the end of one and the start of the next. Better to say it is how often an assessment is carried out, e.g. every seven days on a Friday, every 14 days on a Friday, every month on the first Friday, etc.

Recommend the SDT provide a timeline example in the Technical Rationale.

Likes 0	
Dislikes 0	

Response

Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO

Answer	
Document Name	

Comment

Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Ameren agrees with and supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	
Document Name	
Comment	
The Question #3 of the survey does not seem to align with the current draft of the definition, i.e. the definition doesn't set the Study Frequency to monthly. BC Hydro advocates for an entity to establish what an optimal Study Frequency would be, and not have a prescripted minimum in the Requirement.	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	
Document Name	
Comment	
As discussed in our response to Q1 regarding Study Frequency, the time period between when ERAs are performed could be confused to mean the time between the end of one and the start of the next. The language should be clarified to refer to how often an assessment is carried out, e.g. every seven days on a Friday, every 14 days on a Friday, every month on the first Friday, etc. Additionally, the SRC recommends that the SDT provide a timeline example of how the study process is intended to function in the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	

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

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Appropriate
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Appropriate
Document Name	
Comment	
WAPA concurs with the concept of monthly performance of Near-Term OPERAs, but this conflicts with the proposed Near-Term OPERA definition which states "no more than six weeks." Furthermore, experience has shown that Reliability Standard references to "monthly" have been inconsistently interpreted by compliance authorities. Therefore, WAPA recommends the following clarifying changes to Requirement R1, Part 1.1.2, in combination with the changes suggested to Part 1.1.1 above: ***1.1.2 The Near-Term OPERA maximum Study Frequency shall not exceed six weeks.***	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Appropriate
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	Appropriate
Document Name	
Comment	
Tacoma Power concurs with the MRO NSRF comment that a visual timeline example is needed in the Technical Rationale to understand the study period frequency and duration.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Appropriate
Document Name	
Comment	
Texas RE noticed that this question has the statement: Study Frequency (how often a Near-Term OPERA is performed). The proposed definition of Study Frequency, however, is the time period between Energy Reliability Assessments are performed. Texas RE encourages the SDT to consider the scenario where forecasted weather changes significantly. Can the Near-Term OPERA be redone within the Study Period of the existing Near-Term OPERA? If so, this should be included in R1.1.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Appropriate

Document Name	
Comment	
Need some clarification regarding to R1.1 part regarding to timeline. Please provide some example to clarify. But monthly review is reasonable.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Appropriate
Document Name	
Comment	
ISO-NE agrees that at least monthly would be appropriate, however, ISO-NE also believes that each BA should be able to define their own Study Frequency in their RC reviewed OPERA. (See ISO-NE reponse for R1 suggested modification. ISO-NE also recommends providing a timeline example in the Technical Rationale Document to show what each of the definitions mean and where they could fall in a BA's OPERA Plan. ISO-NE will submit a redline version of TOP-0XX-X in the response for Question #13	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Appropriate
Document Name	
Comment	
PNMR supports the requirement to perform a Near-Term OPERA no less than monthly.	
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	Appropriate
Document Name	
Comment	

We believe the maximum Study Frequency is appropriate; however, we recommend modifying the language of proposed Requirement 1.1.2 to include the newly defined term Study Period. Please consider the proposed language below:

"The Study Frequency will be set such that the Study Period covered by the current Near-Term OPERA must extend into the Study Period covered by the next subsequent Near-Term Opera. The maximum allowable Study Frequency is 1 calendar month."

Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	Less frequent
Document Name	
Comment	

Any requirements regarding frequency of assessments should be based on the specific facts and circumstances of the region. Is the requirement to perform Near-Term OPERAs intended to be a requirement that applies all year round, or only in defined seasons or months? Depending on the region, having an affirmative requirement in all months may not be necessary.

Likes 0	
Dislikes 0	
Response	

Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC

Answer	Less frequent
Document Name	
Comment	

GSOC does not agree with the temporal requirements described. GSOC is of the opinion that the BA should be able to determine the specifics regarding ERAs in its area. GSOC is supportive of the alternate language being submitted by Southern Company.

Likes 0	
Dislikes 0	
Response	

Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company	
Answer	Less frequent
Document Name	
Comment	
Southern Company supports the EEI comments and does **not** agree with the ERA Temporal Requirements.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Less frequent
Document Name	
Comment	
EEI does not agree with the ERA Temporal Requirements. Performance of ERAs should provide regional flexibility and be based on the operational experience of the Balancing Authority to identify when an ERA should be performed, associated time frames, and frequency of the ERA such that the resulting ERA is meaningful and useful in addressing any potential reliability concerns. An ERA Operating Process including a technical rationale to document that process should be sufficient.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Less frequent
Document Name	
Comment	
AZPS feels the performance of ERAs should provide regional flexibility and be based on the operational experience of the Balancing Authority to identify when an ERA should be performed, time frames associated, and frequency of the ERA such that the resultant ERA is meaningful and useful in addressing any potential reliability concerns. An ERA Operating Process with the requirement to address the rationale would be sufficient.	
Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	Less frequent
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #3.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	Less frequent
Document Name	
Comment	
There is already the regular Resource Adequacy process for BAs and Load Serving Entities to perform monthly, seasonally, and annual evaluations. There is no need to define a new process.	
Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	More frequent
Document Name	
Comment	
BPA believes these assessments would provide the most value if performed for approximately the next week out based on the quality of available data; for example: variable energy resources, load and weather forecasts. BPA believes that the maximum study frequency should be 7 days. This question in the comment form refers to **minimum** study frequency, however the standard itself refers to **maximum** study frequency. Please double check which word is intended. Minimum seems to make more sense, however it may be more clear to state that the requirement is to assess every hour seven days out.	

This sentence appears to have a typo, and also, we don’t understand what is meant by future/**prompt**: “…future/prompt and assessment and will be performed at least monthly.”	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	More frequent
Document Name	
Comment	
-Suggest that the minimum study frequency be at least once every two weeks.	
Likes 0	
Dislikes 0	
Response	

4. Energy Reliability Assessment: R1.1 and R1.2 are intended to add requirements that outline the elements that should be included in a Near-Term OPERA but allow Balancing Authorities (BA) with different concerns to have flexibility to implement the assessment such that the assessments are useful. Do you agree with the level of specificity in these requirements? If not, would you prefer that the requirements related to this are more or less specific? Additionally, please comment on what requirements should be removed, clarified, or changed.

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

Answer	
Document Name	

Comment

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

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	
Document Name	

Comment

The proposed elements in the OPERA go beyond a Balancing Authority's function and extend into those of a Transmission Operator (TOP), specifically, Parts 1.2.3 and 1.2.4 and Table 1, footnotes 1 and 2. This needs to be reconsidered and assigned to the appropriate function. It is difficult to conceive how a Balancing Authority can prepare a more extensive look ahead that considers transmission usage, outages and contingencies that result in the loss of supply without the Transmission Operator performing a parallel analysis. At a minimum, the TOP should consider System Operating Limits (SOLs) to ensure they are not exceeded in the OPERA. Alternatively, the scope of the OPERA could be narrowed to focus solely on the ability of a BA to adequately meet its anticipated energy needs via unit commitment. Under this approach, no analysis of transmission would need to be performed and could be accomplished entirely within the BA's purview; however, it would also reduce the usefulness of the study. To the extent a more holistic approach is retained, the SRC recommends the applicability of TOP-XXX be expanded to include the TOP. 4. Applicability: 4.1. Functional Entities: 4.1.1. Balancing Authority 4.1.2. Reliability Coordinator 4.1.3. Transmission Operator The SRC also notes that the use of the term "expected" throughout part 1.2 renders part 1.2 ambiguous regarding the degree of certainty required before a potential event or a particular Resource status or contingency must be included in the base case. The SRC recommends that the term "expected" be replaced with the term "projected" to provide clarity on this point. The SRC also requests that the drafting team provide additional guidance on this point in the technical rationale or a whitepaper. Additionally, part 1.2.4 is unclear regarding whether all contingencies are intended to be included in each study execution. The current wording implies that all contingencies should be included, but that might go beyond the standard's underlying purpose of addressing energy assurance. The SRC recommends that the standard language be clarified and additional guidance be provided in the technical rationale or a whitepaper to address this ambiguity.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
Ameren agrees with and supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	Should be less specific
Document Name	
Comment	
TOP-002 already defines the elements that a BA should consider for next-day assessment. There is no need to define anything new.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	Should be less specific
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #4.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Should be less specific

Document Name	
Comment	

AZPS does not agree with the specificity in these requirements, the current R1.1 requirements for Study Frequency, Study Duration, and Study Temporal Resolution and the R1.2.2 requirements for base cases to be too specific. The study parameters should provide regional flexibility and be based on the operational experience of the Balancing Authority such that they are developed by the Balancing Authority with a rationale for how those parameters were determined.

Likes 0	
Dislikes 0	
Response	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

Answer	Should be less specific
Document Name	
Comment	

The applicability of TOP-XXX must be expanded to include the TOP.

In addition, to the extent TOP-XXX requires BAs (and TOPs) to consider generator specific factors such as: fuel supply and inventory, consumable fuels, environmental constraints, emission limits, etc., in preparing its OPERA, TOP-XXX *must* also include a corresponding requirement for Generator Operators (GOP) to provide the BA and TOP with this information for the time horizon required.

4. Applicability:

4.1. Functional Entities:

4.1.1. Balancing Authority

4.1.2. Reliability Coordinator

4.1.3. Transmission Operator

4.1.4. Generator Operator

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	Should be less specific
Document Name	
Comment	
BC Hydro believes that the Requirement is too prescriptive. The “process” that is developed should be adequate to cover what is needed by the entity.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Should be less specific
Document Name	
Comment	
EEI does not support the proposed R1.1 and R1.2. Requirements. Those related to Study Frequency, Study Duration, and Study Temporal Resolution, and the requirements for base cases, which we believe are too specific. The study parameters should provide regional flexibility and be based on the operational experience of the Balancing Authority such that they are developed by the Balancing Authority with a rationale for how those parameters were determined. See the proposed language offered in our response to question 2.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Should be less specific
Document Name	
Comment	
ISO-NE believes that each BA should be able to determine its own Near-Term Opera Study Frequency, Study Period, and Study Temporal Resolution with corresponding rationale for each as well as a Base Case for the OPERA Study. ISO-NE will submit a redline version of TOP-0XX-X in the response for Question #13	
Likes 0	
Dislikes 0	
Response	

Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company	
Answer	Should be less specific
Document Name	
Comment	
Southern Company supports the EEI comments and does **not** support the proposed R1.1 and R1.2. Requirements.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC	
Answer	Should be less specific
Document Name	
Comment	
GSOC does not agree with the level of specificity in the requirements, believing them to be overly specific. Rather, the requirements should be determined by each BA based on its operational experience. GSOC is supportive of the alternate language being submitted by Southern Company.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Should be less specific
Document Name	
Comment	
The standard mentioned the “fuel supply and inventory concerns and fuel switching capabilities”. To cover a wide range of resources, this part needs to state more generic. MH also support MRO NSRF’s vote and comments for this one.	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	

Answer	Should be less specific
Document Name	
Comment	

Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.

Likes 0	
Dislikes 0	
Response	

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

Answer	Should be less specific
Document Name	
Comment	

BPA recommends that the requirements be less specific. The details should be left to the BA running the studies based on the key aspects of the systems they study. This would allow for regional flexibility.

BPA suggests Requirement 1.2.3 be changed from "transmission usage" to "transmission deliverability". BPA understands 1.2.3 is requiring the BA to ensure that the energy is deliverable to the load and this is commonly referred to as transmission deliverability.

BPA suggests that throughout the standard the term "case" should be changed to "assessment", including 1.2 and Table 1. Base case implies a power flow study is being performed. It is possible to meet the requirements of an OPERA using various methods of system analysis.

Likes 0	
Dislikes 0	
Response	

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	Should be less specific
Document Name	
Comment	

Tacoma Power endorses MRO NSRF comments.

Likes 0	
Dislikes 0	

Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Should be less specific
Document Name	
Comment	

Assessment frequency and scenarios should be customizable based on the facts and circumstances of the region.

Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Should be less specific
Document Name	
Comment	

The proposed elements in the OPERA go beyond a Balancing Authority's function and extend into those of a Tranmission Operator (TOP), specifically, Parts 2.1.3 and 2.1.4 and Table 1, footnotes 1 and 2. This needs to be reconsidered and assigned to the appropriate function.

It is difficult to conceive how a Balancing Authority can prepare a more extensive look ahead that considers transmission usage, outages and contingencies that result in the loss of supply without the Transmission Operator performing a parallel analysis. At a minimum, the TOP should consider System Operating Limits (SOLs) to ensure they are not exceeded in the OPERA.

Alternatively, the scope of the OPERA could be narrowed to focus solely on the ability of a BA to adequately meet its anticipated energy needs via unit commitment. Under this approach, no analysis of transmission would need to be performed and could be accomplished entirely within the BA's purview; however, it would also reduce the usefulness of the study.

To the extent a more holistic approach is retained, the MRO NSRF recommends the applicability of TOP-XXX be expanded to include the TOP.

In addition, to the extent TOP-XXX requires BAs (and TOPs) to consider generator specific factors such as: fuel supply and inventory, consumable fuels, environmental constraints, emission limits, etc., in preparing its OPERA, TOP-XXX *must* also include a corresponding requirement for Generator Operators (GOP) to provide the BA and TOP with this information for the time horizon required.

4. Applicability:

4.1. Functional Entities:

4.1.1. Balancing Authority

4.1.2. Reliability Coordinator

4.1.3. Transmission Operator

4.1.4. Generator Operator

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	Appropriately specific
Document Name	

Comment

- Requirements 1.1 and 1.1.4 use the term “Study Duration”; however, this is not a defined term. We recommend moving Requirement 1.1.4 to become the new Requirement 1.1.2, renumbering the subsequent Requirement Parts, and updating the language as follows:

“The total duration of the Study Period shall be no less than 7 days.”

- We agree with the stated intent of allowing BAs the flexibility to implement assessments that address their specific concerns; however, the proposed language of Requirement 1.2 seems to indicate that only the identified subparts shall be included in the base case. Furthermore, Requirement R1 ends with the phrase “The Near-Term OPERA shall:” and part 1.2 begins with the same phrase. We recommend modifying Requirement 1.2 as follows:

“Use a base case that, at a minimum, includes:”

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	Appropriately specific
Document Name	

Comment

PNMR agrees with level of specificity for R1.1 and R1.2.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Appropriately specific
Document Name	
Comment	
-Suggest revising R1.1.3 language to read: 1.1.3. The Study Temporal Resolution “shall be no more than 1-hour”.	
Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Appropriately specific
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1,6	
Answer	Appropriately specific
Document Name	
Comment	
While specificity is good, the ambiguity in the existing proposed language is problematic. Please see suggestions for Requirement R1, Parts 1.1.1 and 1.1.2 above. Additionally, Requirement R1, Part 1.1.3 has two problems: first, it uses atypical language for a Reliability Standard; and, second, the maximum of one hour seems arbitrarily short especially considering energy scheduling that can be appropriately conducted at other periodicities including three, six, twelve or longer hours. The suggested modification is: ***1.1.3. The Study Temporal Resolution shall not exceed 3 hours.***	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Appropriately specific
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

5. Near-Term OPERA Scenarios: The SDT is proposing to require the development and analysis of scenarios which have a reasonable risk of occurring through the time-horizon of the Near-Term OPERA. Table 1 includes standard scenarios that shall also be evaluated. These scenarios shall have documented criteria which specify when implementing a mitigation Operating Process solution is required. Do you agree with the language in the requirement? If not, please comment with alternate language and explanation of recommended changes.

Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

The Table 1 scenarios are appropriate, but Requirement R2, Part 2.1.2 is ambiguous and creates an open-ended obligation for a BA to develop, document, and maintain a list of scenarios with "likely risk of occurring" without defining likely risk (e.g., is a 1-in-10 year LOLE event "likely" in any Near-Term OPERA horizon?). Furthermore, Requirement R2 uses atypical language for a Reliability Standard. WAPA recommends the following clarifying changes to Requirement R2:

R2. Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed Near-Term OPERA scenarios.

2.1. The Near-Term OPERA scenarios developed shall include:

2.1.1. All scenarios listed in Table 1

2.1.2. Any additional scenarios within the Operations Planning time horizon selected by the Balancing Authority according to its documented risk-based approach that considers.

2.2. All The Balancing Authority shall establish criteria for each Near-Term OPERA scenarios to determine when implementing an Operating Process is required.

Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Minnesota Power supports EEI's comments.

Likes 0	
Dislikes 0	
Response	

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

Table 1 is overly prescriptive, even dictating the level of supply interruption, e.g., 50%, to be considered. To the extent TOP-XXX requires BAs to consider factors such as: fuel supply and inventory, consumable fuels, environmental constraints, emission limits, etc., in preparing its OPERA, TOP-XXX must also include a corresponding requirement for Generator Operators (GOP) to provide the BA with this data over the time horizon required as BAs.

In addition, several proposed elements in the OPERA go beyond a Balancing Authority's function and extend into those of a Tranmission Operator (TOP), specifically, Table 1, footnotes 1 and 2. This needs to be reconsidered and assigned to the TOP function.

Recommendation: The MRO NSRF recommends an alternative. Let the OPERA process (or methodology) dictate the process and scenarios to be studied. This would eliminate the need for Table 1 in the standard.

Consider assigning the development of the OPERA process (or methodology) to the RC and a corresponding requirement on BAs and TOPs to follow the RC's process. This would ensure consistency and coordination in an efficient manner.

Finally, the MRO NSRF recommends the applicability of TOP-XXX be expanded to include the TOP and GOP functions as detailed in our response to Question 4.

Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

Is the proposed requirement that entities have distinct Operating Plans to address every possible scenario, depending on whether or not an EEA 2 or 3 is forecasted? What kind of documentation or evidence would be required to demonstrate a sufficient Operating Plan? Entities already have operation plans with regard to EEAs; would those plans potentially be sufficient, depending on the circumstances and scenario?

Likes 0	
Dislikes 0	
Response	

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No

Document Name	
Comment	

Tacoma Power supports the comments from MRO NSRF.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

-Do not understand the meaning of the phrase "specific segment of a pipeline" for Footnote 3 (Generators with common fuel supply are all generators on a specific segment of a pipeline or multiple stations with a common fuel source. The fuel source should include pipelines, suppliers of consumable fuels, and variable sources like solar and wind energy.). Please clarify.

-Table 1. Near-Term OPERA Scenarios are to broad and time-consuming from a resource perspective (e.g., computing power) to obtain an effective outcome. Additionally, this effort appears to be somewhat duplicative of other resource adequacy efforts.

Likes 0	
Dislikes 0	
Response	

Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO

Answer	No
Document Name	
Comment	

Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.

Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	
Comment	

Some discussions regarding to the contingency event for “Fuel supply interruption that results in the loss of at least 50% of the largest subset of supply resources” might be not true for hydronic commany. But the group members discussed “drought condition” or “frazil ice” might cause the scenario but very rare. Do we want to do the OPERA under very rare system conditions as a normal practice or each BA can select and choose its own OPERA’s scenarios? MH also supports MRO NSRF’s vote and comments for this one.

Likes 0	
Dislikes 0	
Response	

Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC

Answer	No
Document Name	
Comment	

GSOC does not agree with the specific scenarios described in Table 1. GSOC is supportive of the alternate language being submitted by Southern Company.

Likes 0	
Dislikes 0	
Response	

Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company

Answer	No
Document Name	
Comment	

Southern Company supports the EEI comments and disagrees with the language in the standard concerning the development scenarios and the inclusion of Table 1 along with requirements to implement a mitigation process.

Likes 0	
Dislikes 0	
Response	

Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	

Comment

ISO-NE believes that each BA should be able to determine its own Near-Term Opera Study Scenarios. Recommend utilizing the Table in the Technical Rationale or Implementation Guidance Document.

Recommended Edits to R2:

R2. Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed Near-Term OPERA scenarios or a method of scenario development. [Violation Risk Factor:] [Time Horizon: Operations Planning]

2.1. The Near-Term OPERA scenarios developed shall include:

2.1.1. The scenarios listed in Table 1; and

2.1.2. Scenarios with a likely risk of occurring within the Near-Term OPERA Study Period, which may include;

• seasonally appropriate historical events;

• generation specific fuel or energy contingency scenarios;

• consideration of wind and solar performance, and;

• weather events.

2.2. All Near-Term OPERA scenarios developed in R2.1 shall have documented criteria which specify when the implementation of an Operating Process is required.

ISO-NE will submit a redline version of TOP-0XX-X in the response for Question #13

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	

Comment

Ameren agrees with and supports MISO's comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI disagrees with the language in the proposed standard concerning the development scenarios and the inclusion of Table 1 along with the requirements to implement a mitigation process. EOP-011 already requires the Balancing Authority to develop RC-reviewed Operating Plans to mitigate Energy Emergencies and covers all timeframes such that there are no gaps. See EOP-011-4, R2 below along with the time horizons of applicability. Additionally, the Balancing Authority does not have authority to mitigate a projected energy shortage. For instance, the Balancing Authority cannot procure transmission service, contract for generations, require fuel deliveries, etc.

EOP-011-4

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**]***

EEI also believes that an Energy Reliability Assessment (ERA) should be designed to vary by region and that the Balancing Authority should have the flexibility to define the criteria. We also do not support the hypothetical scenarios which are included in Table 1 and do not think it should be part of the ERA's purpose, as these may cause confusion in priorities and result in unnecessary planning. This aligns with the following statement on page 4 of the SAR: "For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Instead, each entity will establish and document criteria as part of complying with the Standard."

To meet regional demands, Balancing Authorities must be provided with the flexibility to define their own scenarios based on regional operational experience. EEI suggests that ERA studies include general requirements for variations in generation, load, and fuel. This approach is needed to provide regional flexibility and prevent unintended consequences from responses to extreme-forecasted, low-probability scenarios while ensuring compliance with NERC operating requirements.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

A. As drafted, R2 Parts 2.1 and 2.2 appear to be a measure of compliance for R2. BC Hydro recommends reviewing and revising.

B. As drafted, R2 allows an entity to have a method of scenario development or a list of scenarios. With this allowance, it is unclear how this Requirement can be enforced (or the subsequent Requirements that reference scenarios) should an entity choose to only have a method of scenario development. BC Hydro recommends reviewing and revising R2 and subsequent Requirements to align with an entity choosing the option of having a method instead of specific scenarios.

C. BC Hydro recommends that the Near-Term OPERA scenarios development should be part of the process in R1.

D. The use of “Reliability Coordinator-reviewed” language in R2 appears to establish a requirement for the RC to review the BA’s scenarios/method to develop as part of the BA’s compliance for R2 ie the BA’s scenarios/method would be found non-compliant per R2 if the RC hadn’t reviewed it. As there are specific Requirements for the BA to submit R2 scenarios/method of development to the RC in R3, BC Hydro suggests that this is not required and recommends revising R1 wording to remove this language.

E. The use of “likely” in Part 2.1.2 makes the requirement ambiguous. Recommend revising to remove the word “likely” and include wording that allows the applicable entity to determine which scenarios, if any, to include.

F. BC Hydro notes that other Standards (including BAL-002-3 R2, EOP-010-1 R3, etc.) reference Operating Process. Does R2 Part 2.2 imply that all Operating Processes as developed under other Standards need to be reviewed and included if applicable?

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	No
Document Name	

Comment

The fuel contingency scenarios listed in Table 1 are broad enough that the SRC is concerned that these contingencies would result in a forecasted EEA2 or EEA3 a disproportionate amount of the time. For example, a contingency that includes loss of 50% of all solar generation on a clear, hot Texas day would likely result in a forecasted EEA2 or EEA3 for ERCOT a significant portion of the time, as would a contingency that includes loss of 50% of all wind generation under certain operating conditions. The SRC recommends that the fuel contingency scenarios be scaled back to minimize the number of false positives likely to result from studying these scenarios. It is also unclear how broadly the term “resources sharing a common fuel supply” is intended to be construed. For example, would all coal Resources that receive deliveries from the same railroad line or the same coal mine be considered to share a common fuel supply? Would all hydroelectric Resources on a given waterway or in a given region be considered to share a common fuel supply? Under what circumstances would nuclear Resources be considered to share a common fuel supply? The SRC recommends that the scope of this term be clarified and narrowed to address these ambiguities. Additionally, Table 1 is overly prescriptive, even dictating the level of supply interruption, i.e., 50%, to be considered. To the extent TOP-XXX requires BAs to consider factors such as fuel supply and inventory, consumable fuels, environmental constraints, emission limits, etc., in preparing its OPERA, TOP-XXX must also include a corresponding requirement for Generator Operators (GOP) and other registered entities to provide the BA with this data over the time horizon required for the BAs to construct compliant contingencies and otherwise fulfill their obligations under the standard. Recommendation: Alternatively, let the OPERA process (or methodology) dictate the process and scenarios to be studied. This would eliminate the need for Table 1 in the standard. Consider assigning the development of the OPERA process (or methodology) to the RC with a corresponding requirement for BAs and TOPs to follow the RC’s process. This would ensure consistency and coordination in an efficient manner.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	

Comment

PNMR agrees with EEI's comments regarding Near-Term OPERA Scenarios:

The language in R2.2 does not align with the intent of this requirement. While R2.2 specifies that an Operating Process is required, there is no specific mention that the Operating Process is intended to mitigate issues identified as BPS risks or what constitutes an Operating Process mitigation. To address this concern, we offer the following proposed changes in bold face below):

2.2. All Near-Term OPERA scenarios developed in R2.1 shall have documented criteria which specify when implementing a**n mitigation** Operating Process **solution** is required.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

AZPS does not agree with the language in this requirement. The EOP-011 requirements already cover the intended outcomes of this proposed requirement.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
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 Requirement 2.1.2 is too ambiguous. How is an auditor to assess a "likely risk of occurring"? How much of a risk is "likely" enough for it to be considered in the Near-Term OPREA scenarios? We recommend giving the BA an appropriate amount of discretion in determining whether a given scenario should be considered without the burden of proving its likelihood of occurring. To accomplish this objective, we recommend deleting Requirement 2.1.2 and modifying Requirement 2.1 as follows: "The Near-Term OPERA scenarios developed shall, at a minimum, include:"	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #5.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	No

Document Name	
Comment	
Every BA/Load Serve Entity has different situations. TOP-002 has already defined the elements a BA should consider. There is no need to define anything new.	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies - 6 - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The two fuel supply contingency scenarios call for modeling "the loss of at least 50% of the largest subset of supply resources sharing a common fuel supply ... for the duration of the study period." Applying that assumption to wind or solar output may not make sense for several reasons. First, the capacity accreditation for wind and solar resources that determines the level of output that is relied on for meeting demand during peak periods, as calculated using an Effective Load Carrying Capability analysis or similar method, is typically significantly lower than their nameplate capacity. As a result, it is not clear whether the determination of the "largest subset of supply resources" and application of.the 50% loss assumption should be based on the nameplate capacity or the accredited capacity value of the resource. The determination of the "largest subset of supply resources" should presumably be based on the accredited capacity value as that is the expected level of output during peak periods, but applying the 50% loss to the accredited capacity value of those resources may double count risk that was already accounted for in the capacity accreditation analysis. Finally, assuming the 50% loss persists "for the duration of the study period" does not reflect the typical performance of wind and solar resources, as lulls in output typically only persist for hours, or days in rare cases. For studies extending out less than a week from real-time, wind and solar output forecasts could likely also be used as an input into the analysis.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE inquires as to why Requirement R2 requires Near-Term OPERA scenarios or simply a method to develop scenarios. This makes developing the actual scenarios seem optional. If the BA chooses the latter, Requirement Part 2.1 would not be applicable.

In Requirement R2.2, Table 1 already specifies when an Operation Process is required. Texas RE recommends the SDT clarify Table 1 Footnotes 3 and 4 for Solar and Wind resources. For example, for a solar farm, would half of the panels need to be covered by clouds? Or would it be 50% in a specific county?

Texas RE noticed that “study period” should be capitalized in Table 1 as it is proposed to be defined.

Likes 0	
Dislikes 0	
Response	

6. Balancing Authority (BA) Requirements: The proposed Requirements 3, 4 and 5 are modeled after Requirements 2, 3 and 4 in EOP-011-2 to ensure that an individual BA's Near-Term OPERA processes are reviewed by the Reliability Coordinator (RC) based on compatibility and inter-dependency with other BA's Near-Term OPERA processes and scenarios, and have the BA address reliability risks identified by the RC. Do you agree that the requirements for the BA to have its processes reviewed by the RC and any RC-identified issues be addressed by the BA are reasonable?

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	No
Document Name	
Comment	
This adds an unnecessary burden to both BAs and RCs.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #6.	
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 agree with the overall concept of the RC reviewing the Near-Term OPERA process and scenarios; however, we have concerns with the burden being placed upon the RC. To date, there are 5 specific requirements that require the RC to review documents created and submitted by an external entity. Most of the reviews required by the various Reliability Standards (3 out of 5) require the RC to review and respond to the submitting entity within	

30 calendar days of receipt. If approved as currently written, the proposed Requirement R3 would increase the total number of reviews required to be completed within 30 calendar days to 4 out of 6 total.

Given that the proposed Requirement R3 is an annual review, we recommend giving the RC more time to perform its review. We believe that 90 calendar days is a more appropriate timeframe for the RC review; particularly considering that R4.1 requires the RC to consider compatibility with other BAs Near-Term OPERA process and scenarios.

Lastly, proposed Requirements 4.3 and R5 seem to contradict one another. Is the BA required to revise and resubmit its Operating Process(s) and scenarios to the RC within 30 days of receipt (R5) or as prescribed by the RC (R4.3)? We recommend modifying Requirement 4.3 as follows:

"Notify each Balancing Authority of the results of its review."

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

AZPS does agree that Operating Processes should be reviewed by the RC, the EOP-011 requirements already cover the intended outcomes of this proposed requirement.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	No
Document Name	

Comment

A. R4 Part 4.1: It is not clear whether the "other Balancing Authorities" are within the RC footprint. If the RC is expected to directly engage with BAs outside its own footprint, this would expand the scope of R1 and R2 expectations and the RC review requirements. BC Hydro recommends revising the language to clarify that it is the other BAs in the RC footprint.

B. It is not clear what data, if any, would need to be provided by the BA to the RC along with its process and scenarios/method. It is not clear if an RC can ask for further information from the BA. And it is not clear once the RC has completed their review, what, beyond the results, will be shared between the BA(s) and RC(s). It is not clear if the base case data listed in R1 will be passed along to RC and if it's a method of scenario development an entity has chosen, only the method or scenarios or further scenario data per R2 would be passed to the RC. There does not seem like there is a need to share this info or data with other BAs or RCs. Should this need exist, BC Hydro recommends that data sharing agreements would be required to enable the exchange of relevant information. BC Hydro recommends revising R3 and R4 to clarify what is being submitted by the BA to the RC and what an RC could potentially be requesting of the BA.

C. Requirement R5 references "resubmit its Operating Process(s)". This appears to be a typo and R5 should be referring to Near-Term OPERA process. As well, R4.3 specifies that the RC can specify any timeframe for resubmittal and R5 specifies a 30 calendar day timeframe. If the RC specifies a timeframe longer than 30 calendar days, then these two Requirements would seem to conflict. BC Hydro recommends revising R5 to be "to its Reliability Coordinator within the timeframe specified in R4.3."

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

While EEI agrees that the RC should review the BA Operating Process proposed in the draft language provided by EEI, the RC review should be structured to be less restrictive than the review in EOP-011. In EOP-011, the RC is reviewing Operating Plans to mitigate actual emergencies, which is a reliability issue; conversely, in this standard, the RC is reviewing an Operating Process for forecasted emergencies.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Ameren agrees with and supports MISO's comments.

Likes 0	
Dislikes 0	

Response

Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company

Answer	No

Document Name	
Comment	
Southern Company supports the EEI comments and agrees that the RC should review the BA Operating Process, the RC review should be structured to be less restrictive than the review in EOP-011.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC	
Answer	No
Document Name	
Comment	
GSOC agrees with the general concepts expressed in Requirements 3 – 5, but not the specific language. GSOC is supportive of the alternate language being submitted by Southern Company.	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	
Answer	No
Document Name	
Comment	
Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	

Comment	
-Suggest changing: R3. The Balancing Authority shall submit for review the Near-Term OPERA process and scenarios to the Reliability Coordinator annually on a mutually-agreed upon schedule. to read: R3. The Balancing Authority shall submit for review the Near-Term OPERA process “developed under R1” and scenarios “developed under R2” to the Reliability Coordinator annually on a mutually-agreed upon schedule. -Amend: R5. Each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R4 and resubmit its “Near-Term OPERA processes” and scenarios to its Reliability Coordinator within 30 calendar days of receipt.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Consider assigning the development of the OPERA process (or methodology) to the RC and a corresponding requirement on BAs and TOPs to follow the RC’s process **System Operating Limits Methodology for the Operations Horizon** (**FAC-011-4, R9**). This would ensure consistency and coordination in an efficient manner and eliminate the need for RC review.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR agrees with EEI in support of the approach to have BA Near-Term OPERA processes reviewed by the RC based on compatibility and inter-dependency with other BA's Near-Term OPERA processes and scenarios, and have the BA address reliability risks identified by the RC.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Suggested Minor edits to simplify R3: **R3.** The Balancing Authority shall review and submit the Near-Term OPERA process and scenarios to its Reliability Coordinator at least annually. ISO-NE will submit a redline version of TOP-0XX-X in the response for Question #13	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	

Answer	Yes
Document Name	
Comment	
We agreed the BA should submit OPERA process and scenarios to its RC on a mutually-agreed upon schedule (for example annually) and address any relaiibity risks identified by its RC within 30 calendar days receipt.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends the SDT clarify who develops the “mutually agreed-upon schedule” in Requirement R3. Texas RE recommends the SDT clarify which process and scenarios Requirement R3 and Requirement R5 refers to. If it is the process and scenarios in R1 and R2, it should state that.	
Likes 0	
Dislikes 0	
Response	

7. Balancing Authority notifies the RC within 24 hours of identified forecasted Energy Emergencies: Once the Near-Term OPERA has been performed, per the RC reviewed Operating Process, R6 requires the BA to notify its RC within 24 hours of any identified forecasted Energy Emergencies. The 24 hours notification to the RC of all forecasted Energy Emergency provides time for the BA to prepare and respond to the forecasted Energy Emergency. Do you agree that the BA must notify the RC within 24 hours? If not, please comment what would be more appropriate and explain why.

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

Is the intent that the entity notify the RC of potential forecasted EEAs under any of the scenarios? In other words, even a single scenario identifying a possible EEA would trigger this requirement? Depending on the time period over which the OPERAs are conducted (and whether, in the normal course of business, alternative supply has been sought/procured yet) this may be overinclusive. An alternative might be, that if a possible EEA is identified for a future time period, the entity be given the opportunity to take mitigation action, including procuring additional supply. Given that the OPERA could be looking a month or more out, it is appropriate for the entity to have a chance to remediate any potential deficits.

Likes 0	
Dislikes 0	

Response

Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC

Answer	No
Document Name	

Comment

GSOC agrees that the BA should notifty its RC of any reliability issues, but not the specific language as written. GSOC is supportive of the alternate language being submitted by Southern Company.

Likes 0	
Dislikes 0	

Response

Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company supports the EEI comments and agrees that the results of an ERA should only be provided to the RC upon identification of a reliability issue.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
While EEI does agree that an ERA should be performed as specified, the results should only be provided to the RC upon identification of a reliability issue. Current TOP-002-5 already requires the BA to provide a next-day Operating Plan to the RC which contains information about potential energy emergencies (R7), and the BA notifies the RC when its Emergency Operating Plan is implemented as required in EOP-011 (R5). These notifications are necessary to ensure reliability; however, we do not agree with the time requirement in R6. The 24-hour requirement in R6 puts this type of communication on par with actual Emergencies and is unnecessary for BES reliability.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
This requirement seems to overlap with the existing TOP-002-4 Requirements R4 and R7. BC Hydro suggest that there is not enough technical justification for such new requirements as drafted, and would duplicate existing Requirements.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	

Comment	
AZPS does agree the ERA should be performed and provided to the RC, but TOP-002/EOP-011 already cover the intended outcomes of this proposed requirement. The 24 hour requirement in R6 puts this type of communication on par with actual Emergencies and does not increase reliability.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #7.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The MRO NSRF supports a 24-hour notification provision for situational awareness; however, what is done following notification should dovetail with existing standards (TOP-002, TOP-001 and EOP-011) and not introduce new steps that aren't a value-add over existing processes.	
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	

Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
-Amend: 6.1. The Balancing Authority shall notify its Reliability Coordinator within 24 hours “of determining that the criteria developed under R2.2” when Near-Term OPERA results require the implementation of an Operating Process(es).	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	
Answer	Yes
Document Name	
Comment	
Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
MH supports MRO NSRF’s vote and comments for this one.	

Likes 0	
Dislikes 0	
Response	

Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	

The Requirements in R6 needs to be clear as to what the Operating Process(es) are. As currently written any operating process such as normal dispatch and controls may be required in the notification process.

Suggested Edit for 6.1:

6.1. {C}The Balancing Authority shall notify its Reliability Coordinator within 24 hours when Near-Term OPERA results identify a forecasted Energy Emergency.

ISO-NE will submit a redline version of TOP-0XX-X in the response for Question #13

Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	

Ameren agrees with and supports MISO's comments.

Likes 0	
Dislikes 0	
Response	

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes

Document Name	
Comment	
The SRC supports a 24-hour notification provision for situational awareness; however, what is done following notification should dovetail with existing standards (TOP-002, TOP-001 and EOP-011) and not introduce new steps that aren't a value-add over existing processes.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR agrees with obligating the BA to notify the RC of an identified forecasted Energy Emergency, but it is unclear whether the SDT will similarly modify EOP-011-1 to align the Energy Emergency Alert obligations contained in that Reliability Standard with the obligations being set within the proposed TOP Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	Yes
Document Name	

Comment	
It is necessary to notify the RC if a BA forecasts any Energy Emergency. However, it should be within 24 hours after the conditions are confirmed, and not simply identified, because it will take some time for a BA to confirm and verify that the forecasted conditions are accurate.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
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	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	

Texas RE noticed that the verbiage of the question does not match the verbiage of Requirement R6. The question refers to notifying the RC within 24 hours of any identified forecasted Energy Emergencies. The standard states that the RC shall be notified when the Near-Term OPERA results require the implementation of an Operating Process. Not all Energy Emergencies require an Operating Process.

Texas RE encourages the SDT to reevaluate its use of the terms Operating Process and Operating Plan. EOP-011-2 uses the term Operating Plan, while drafted TOP-0XX-X Requirement Part R2.2 requires a that Near-Term OPERA scenarios have criteria to specified when implementing and Operating Process is required. EOP-011-2 does not require every Energy Emergency Alert scenario to have an Operating Plan, which is what TOP-0XX-X table seems to suggest. This could cause confusion as entities implement these standards.

Likes 0	
Dislikes 0	

Response

8. Submit the Near-Term OPERA results to the RC upon request: The requirement to submit the results to the RC upon request is intended to ensure the RC can review the assessment results. This requirement ensures the RC can review the results to verify the processes and scenarios are being implemented and to review any adverse results. Do you agree that the results must be submitted to the RC upon request, for RC review? If not, please comment which would be more accurate and explain why.

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	No
Document Name	

Comment

This Requirement seems to overlap the existing TOP-002-4 R4/R7. BC Hydro suggest that there is not enough technical justification for such new requirements as drafted and would duplicate existing Requirements.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

The assessment results should be forwarded to RC automatically or regularly bases same as the the next day OPA work process (for example Manitoba Hydro to MISO day ahead study work process).

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

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

Likes 0	

Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS agrees that results should be submitted to the RC upon request.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR agrees with the requirement to submit the results to the RC upon request.	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes
Document Name	
Comment	
R6 requires a specific notification, but it may also be beneficial for the BA to regularly share the results, similar to what is done under existing TOP standards.	
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 requirement to submit the results to the RC upon request.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
ISO-NE has no additional comments	
Likes 0	
Dislikes 0	
Response	

Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company	
Answer	Yes

Document Name	
Comment	
Southern Company supports the EEI comments and agrees with the requirement to submit the results to the RC upon request.	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	
Answer	Yes
Document Name	
Comment	
Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.	
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	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	

Tacoma Power supports the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	Yes
Document Name	

Comment

A specific notification when required by R6, but why not regularly share the results similar to what is done under existing TOP standards. Each TOP/BA must notify other entities with a role in their respective plan(s) and provide their OPAs and Operating Plans to the RC; however, unlike EOP-011, TOP-002 does not require the RC to explicitly review, provide feedback and approval (*see* TOP-002-4, requirements R6-R7).

Likes 0	
Dislikes 0	

Response

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

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	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

9. Operating Process Development: The proposed Requirements 7, 8 and 9 are modeled after Requirements 2, 3 and 4 in EOP-011-2 to ensure that there is a plan developed to respond to deficiencies noted during the performance of a Near-Term OPERA. R7 is intended that Operating Processes would be developed before OPERAs are performed and would be a high-level plan of how a BA would approach a forecasted Energy Emergency, not necessarily a step-by-step process. R7 has required actions listed for consideration that are intended to reduce the risk of Energy Emergencies. As written, the requirement provides a list of optional steps to consider as part of an Operating Process. Should the list of requirements for Operating Processes be optional (as written), be required to be addressed for all BAs (as in EOP-011), or removed from R7 entirely? Please provide additional actions or notes which should not be included in this list as comments.

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	The listed actions should be addressed by all BAs (as in EOP-011)
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	The listed actions should be addressed by all BAs (as in EOP-011)
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	The listed actions should be addressed by all BAs (as in EOP-011)
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	The listed actions should be addressed by all BAs (as in EOP-011)
Document Name	
Comment	
PNMR agrees with EEI's commnet: While EEI agrees that all BAs should address all actions, consistent with EOP-011, the SDT should ensure that the emergency operating procedures contained in this proposed Reliability Standard are reviewed to ensure there is no duplication of requirements from EOP-011. EEI also ask for clarification regarding the intent of Requirement R9 RC reviews of the BA's Operating Processes in situations where the responsible RC is also the responsible BA.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	The listed actions should be options (as written)
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	The listed actions should be options (as written)
Document Name	
Comment	
Existing EEA processes should suffice or count toward meeting this Operating Plan requirement. Likewise, RC review of EEA processes should count toward R8.	
Likes 0	
Dislikes 0	

Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	The listed actions should be options (as written)
Document Name	
Comment	

-R7.2 bullet three should be deleted as EOP-011 R2.2.2 governs when an EEA is requested.

-R7.2.1. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency, should be deleted as EOP-011 R2.2.8 speficifically requires this to mitigate an Emergency. This requirement is not appropriate for a forecasted Emergency.

-Delete: 7.2.2. Provisions to determine reliability impacts of:

• cold weather conditions; and

• extreme weather conditions.

is not appropriate – the scenarios in Table 1 address the impacts of these weather conditions on energy resources and fuel supply. The implementation of the Near-Term OPERA process under R3 has already addressed this item.

Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	The listed actions should be options (as written)
Document Name	
Comment	

We agreed the list actions should be options since each utility has its own situations and mitigations for forecasted energy emergincies. For example in Manitoba, we can run Brandon CTs or perform generation scheduling to mitigate.

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	The listed actions should be options (as written)

Document Name	
Comment	

We agree with the stated intent that the steps listed in R7 be optional; however, the current language in the proposed Requirement 7.2 seems to indicate that the identified processes are a minimally required list. We recommend modifying Requirement 7.2 as follows:

“Processes to reduce the probability of forecasted Emergencies including, but not limited to, any or all of the optional actions identified below:”

Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	

The listed actions are overly prescriptive, set a higher bar threshold for performance than existing TOP standards (TOP-002- and TOP-001) in a time horizon that is farther into the future and less certain than TOP-002 and TOP-001, leapfrogs existing TOP standards to move directly into emergency procedures and fails to acknowledge that operating plans (and forecasted risks) may change prior to the operating day.

As written, TOP-XXX-X requires more time and effort to be dedicated to resolving identified risks in a multi-day look ahead as opposed to dedicating these same resources to addressing identified risks in time horizons nearer to real-time.

In addition, the duplication of EOP-011 requirements in TOP-XXX-X introduces the opportunity for “double jeopardy.” As the implementation of these requirements is already covered under EOP-011, R2, there is no need to repeat them here. If EOP-011 is not working as desired, modifications should be made in EOP-011.

Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	

Tacoma Power supports the MRO NSRF comments.

Likes 0	

Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
BPA recommends R7 be removed. R7 is duplicative of EOP-011-2 since a BA should use their EOP-011-2 plan to ensure consistency in the operations horizon. If the SDT is envisioning something different than that plan, please clarify. If R7 is removed, R8 and R9 would also be removed.	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
GSOC is supportive of the alternate language being submitted by Southern Company.	
Likes 0	
Dislikes 0	
Response	

Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
Southern Company supports the EEI comments and does **not** agree with Requirements 7, 8 and 9 as written.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
This is a duplicative requirement to EOP-011-2 R2. Suggest a Requirement modeled after FAC-011-3 R3.3 which references FAC-014 Requirement 6. While certainly not common there is precedent for this type of reference. Additionally the below proposed edit would encorporate the specific item not addressed by EOP-011 R2. Suggested R7 Edit: **R7** Each BA shall develop and maintain one or more Reliability Coordinator reviewed Operating Process(es) to mitigate forecasted Energy Emergencies within its Balancing Authority Area (in accordance with EOP-011 Requirements applicable to the Balancing Authority). **R7.1** Forecasted Energy Emergency Operating Processes shall include (in addition to those prescribed in EOP-011 Requirement 2): -Updated frequency of performing a Near-Term OPERA to monitor if an Energy Emergency Alert continues to be forecasted or forecasted conditions worsen. ISO-NE is submitting a redline version of TOP-0XX in its response to Question 13.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	The listed actions should not be part of the Standard

Document Name	
Comment	

Ameren agrees with and supports MISO's comments.

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	The listed actions should not be part of the Standard
Document Name	
Comment	

EEI does not support Requirements 7, 8 and 9 as written. Instead, EEI suggests requirements that require the development of an Operating Process that contains the information around performance of the ERA. We additionally note, in our other comments, that existing standards are already in place to deal with the identification, communication, and mitigation of actual Emergencies. The ERA should be limited to an assessment that provides awareness for others (as necessary per regional needs and is useful to enhance reliability consistent with roles), responsibilities, and capabilities of the applicable NERC registered entities. We are also concerned that the language contained in R7-R9 appears to be duplicative of EOP-011 and therefore inconsistent with the purpose of this proposed Reliability Standard and would only serve to create confusion.

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	The listed actions should not be part of the Standard
Document Name	
Comment	

Based on BC Hydro's understanding of the reliability need this proposed standard is trying to address, it would be adequately covered by EOP-011.

Likes 0	
Dislikes 0	
Response	

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
Including optional steps in a mandatory Reliability Standard has a high risk of causing confusion and diminishing the auditability and enforceability of the standard. For clarity, the SRC recommends that all optional steps be removed from the standard and placed in a non-binding document, such as the technical rationale or implementation guidance. The listed actions are overly prescriptive, set a higher threshold for performance than existing TOP standards (TOP-002- and TOP-001) in a time horizon that is farther into the future and less certain than TOP-002 and TOP-001, leapfrog existing TOP standards to move directly into emergency procedures, and fail to acknowledge that operating plans (and forecasted risks) may change prior to the operating day. As written, TOP-XXX-X requires more time and effort to be dedicated to resolving identified risks in a multi-day look ahead instead of dedicating these same resources to addressing identified risks in time horizons nearer to real-time. In addition, the duplication of EOP-011 requirements in TOP-XXX-X introduces the opportunity for “double jeopardy.” As the implementation of these requirements is already covered under EOP-011, R2, there is no need to repeat them here. If EOP-011 is not working as desired, modifications should be made in EOP-011.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
AZPS agrees that all BAs should address all actions, consistent with EOP-011, the SDT should ensure that the emergency operating procedures contained in this proposed Reliability Standard are reviewed to ensure there is no duplication of requirements from EOP-011.	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #9.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	The listed actions should not be part of the Standard
Document Name	
Comment	
These are already included in EOP-011.	
Likes 0	
Dislikes 0	
Response	

10. Operating Process Development: The requirement is intended to ensure that there is a plan developed to respond to deficiencies noted during the performance of a Near-Term OPERA. While there are multiple possible types of plans that could be developed (e.g., Operating Plan, Operating Process, Operating Procedure, Corrective Action Plan), the most relevant defined term for responding to a forecasted Energy Emergency is Operating Process. Do you agree with the correct type of plan being an Operating Process? If not, please comment which would be more accurate and explain why.

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	No
Document Name	
Comment	
All the existing EOP and TOP standards use the term Operating Plan, which include the Operating Processes. There is no need to define a new term.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	No
Document Name	
Comment	
R1 appears to use process as a generic term for a type of business process and methodology. R7 uses the defined term Operating Process. The SRC recommends that a different term be used in R1 to avoid potential confusion. The SRC also notes that the definition of Operating Process indicates that an Operating Process includes options to be selected based on real-time conditions. This seems incongruous with the draft standard, which addresses a longer time horizon than real-time. Consequently, the SRC recommends that the SDT revisit the use of an Operating Plan instead of an Operating Process, as an Operating Plan could dovetail into the natural progression of existing standards: OPERAs (TOP-XXX-X), OPAs (TOP-002), RTAs (TOP-	

001) and emergency procedures (EOP-011). In this way, Operating Plans developed pursuant to the OPERA could roll forward and be modified as needed pursuant to TOP-002 Next Day OPA and Operating Plans and TOP-001 Real-Time Assessments (RTA) without having to "recreate the wheel."

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	No
Document Name	

Comment

BC Hydro recommends using the "Operating Plan" term to be in alignment with EOP-011 R2.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Ameren agrees with and supports MISO's comments.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	No
Document Name	

Comment

ISO-NE believes it should be specifically called out as a **forecasted Energy Emergency** since Operating Process is too vague.

ISO-NE is submitting a redline version of TOP-0XX in its response to Question 13.

Likes 0	
Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

The most relevant defined term is Operating Plan or Operating Procedure. The OPERA will initiate the studies to provide the mitigations and solutions to deal with the forecasted Energy Emergency. MH also supports MRO NSRF's vote and comments for this one.

Likes 0	
Dislikes 0	

Response

Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO

Answer	No
Document Name	

Comment

Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

BPA believes Operating Plan is the appropriate term. BPA does not see significant distinction between the Operating Plan already required under EOP-011 and the plan requested in this standard.

BPA would also like to note that the SDT has not differentiated between the terms process and plan in the standard and uses the terms seemingly interchangeably in this comment form. If the SDT envisions something different than the EOP-011 Operating Plan, the distinction needs to be made in the standard.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
It is not clear what the intent is for the review of the Operating Process in R10 and R11 since it introduces a second layer of RC submittal and review as that in R4 and R5. In addition, the timeframe appears to allow 30 calendar days for review and response by which time the Operating Process would have expired and a new one created. Where R1 uses Process to mean a type of business process and methodology, R7 calls Process something that is more like a mitigation plan or operating procedure. The two should be more distinct. In that regard, the SDT should revisit the use of an Operating Plan instead of using an "Operating Process" as this would dovetail into TOP-002 and the natural progression of existing standards: OPERAs (TOP-XXX-X), OPAs (TOP-002), RTAs (TOP-001) and emergency procedures (EOP-011). In this way, Operating Plans developed pursuant to the OPERA could roll-forward and be modified as needed pursuant to TOP-002 Next Day OPA and Operating Plans and TOP-001 Real-Time Assessments (RTA) without having to "recreate the wheel."	
Likes 0	
Dislikes 0	

Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the Operating Process as the correct type of plan.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PMNR agrees that the use of an Operating Process is the most appropriate plan to address a forecasted Energy Emergency.	
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 use of an Operating Process is the most appropriate plan to address a forecasted Energy Emergency.	
Likes 0	
Dislikes 0	
Response	
Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the EEI comments and agrees that the use of an Operating Process is the most appropriate plan to address a forecasted Energy Emergency.	
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	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
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	

Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

11. Address Risks Identified in the Review: R8 is intended to provide RCs with information that is needed to ensure that the plans address the reliability of the system. R9 is needed to ensure that any risk identified by the RC in R7 is mitigated by the BA. The SDT proposes that the BA addresses the risk in its Operating Plan and resubmits it to its RC. R10 requires the BA to revise the Operating Process that was previously reviewed by the RC and found to require modifications. Do you agree with the language in the requirements including the proposed timeframes? If not, please provide updated language in your comment as well as a basis for the recommendation.

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

It is not clear what the intent is for the review of the Operating Process in R10 and R11 since it introduces a second layer of RC submittal and review as that in R4. In addition, the timeframe appears to allow 30 calendar days by which time the Operating Process would have expired and a new one created.

Requirement R7 requires the RC to review and provide feedback on BA Operating Processes on what could be as frequent as a weekly basis. The support for this is cited as EOP-011; however the review process for EOP-011 typically involves the review of annual (and at worst case seasonal) plans. This sort of feedback loop is too administratively burdensome for near real-time operations where speed and nimbleness are critical.

In addition, as stated in our response to Question #9, there is no need to duplicate EOP-011 requirements in TOP-XXX-X. Reiterating requirements from EOP-011 introduces the opportunity for “double jeopardy.” If EOP-011 is not working as desired, modifications should be made in EOP-011.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No

Document Name	
Comment	
Existing EEA processes should suffice or count toward meeting this Operating Plan requirement. Likewise, RC review of EEA processes should count toward R8.	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	
Answer	No
Document Name	
Comment	
Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
The timeline is reasonable and the updated plan needs to be re-submitted from BA to RC. Since there are a few timelines in this TOP, it is better to clarify each timeline for BA and RC to ensure they are on the same page for OPERA. MH also supports MRO NSRF's vote and comments for this one.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC	
Answer	No
Document Name	

Comment	
GSOC is supportive of the alternate language being submitted by Southern Company.	
Likes 0	
Dislikes 0	
Response	
Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company supports the EEI comments and does **not** agree with the language in R7 that includes a timeframe for response.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	No
Document Name	
Comment	
As these requirements are duplicative to EOP-011 Requirements 3, 4, and 5. They should be removed from this Standard if R7 is modified to reflect the suggested changes in ISO-NE response to question 9. ISO-NE is submitting a redline version of TOP-0XX in its response to Question 13.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	

Comment	
Ameren agrees with and supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not agree with the language in R7 that includes a timeframe for response. **See EEI's response to Question 9.**	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
Based on BC Hydro's understanding of the reliability need this proposed standard is trying to address, it would be adequately covered by other Requirements in already effective Standards.	
Likes 0	
Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	No
Document Name	
Comment	

Requirement R7 requires the RC to review and provide feedback on BA Operating Processes on what could be as frequent as a weekly basis. The support for this is cited as EOP-011; however the review process for EOP-011 typically involves the review of annual (and at worst case seasonal) plans. This sort of feedback loop is too administratively burdensome for near real-time operations where speed and nimbleness are critical. In addition, as stated in our response to Question #9, there is no need to duplicate EOP-011 requirements in TOP-XXX-X. Reiterating requirements from EOP-011 introduces the opportunity for "double jeopardy." If EOP-011 is not working as desired, modifications should be made in EOP-011.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS agrees that all BAs should address all actions, consistent with EOP-011, the SDT should ensure that the emergency operating procedures contained in this proposed Reliability Standard are reviewed to ensure there is no duplication of requirements from EOP-011.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
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	

Our concerns for the proposed Requirements R8/R9/R10 are similar to those addressed above with regards to the proposed Requirements R3/R4/R5. To wit, we have serious concerns about the burden being placed upon the RC to coordinate, review, and respond to multiple plans, processes, and procedures from multiple different entities (BA, TOP, etc.) in this and other Reliability Standards. We recommend modifying Requirement R9 to be 90 calendar days as opposed to the currently proposed 30 calendar day requirement.

Additionally, like proposed Requirements 4.3 and R5, Requirements 9.2 and R10 seem to contradict one another. Is the BA required to revise and resubmit its Operating Process(s) andscenarios to the RC within 30 days of receipt (R10) or as prescribed by the RC (R9.2)? We recommend modifying Requirement 9.2 as follows:

"Notify each Balancing Authority of the results of its review."

Lastly, we believe there is a typo in R10. As written, R10 states:

"Each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R7…"

We believe the correct requirement to be referenced is R9 as this would be in alignment with the proposed language of R5.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #11.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD

Answer	No
Document Name	

Comment

BAs should already have a series of Operating Plans for Emergencies per EOP-011 and TOP-002. There is no need for annual reviews which are already covered in EOP-011.

Likes 0	

Dislikes 0	

Response

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6

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

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	Yes
Document Name	

Comment

PNMR supports EEI's comments:

While EEI agrees that the proposed requirements in Requirements 8, 9 & 10 and associated timeframes, we additionally ask that the emergency operating procedures contained in Requirement R8 are reviewed to ensure they do not duplicate any of the requirements in EOP-011.

Requirement R10 states the “Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R7 and resubmit its Operating Process (s) to its Reliability Coordinator within 30 calendar days of receipt” however, we do not see where the RC within Requirement R7 would identify a reliability risk. Please clarify.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1,6

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

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

12. Implementation of Operating Process: R11 is a follow-up from R7, where the BA is now implementing the Operating Process that was previously developed. R12 requires the RC to ensure quick dissemination of critical information to a list of entities which can take appropriate actions to respond to the forecasted Energy Emergency. Does the proposed language clearly outline the responsibilities of the BA and RC in the event of a forecasted Energy Emergency? Is the 24-hour notification window feasible and appropriate for the types of emergency situations that might arise? Please provide any other comments about the language in Requirements 11 and 12.

Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #12.	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
AZPS feels this would not add reliability benefit and would only serve to increase the RC function compliance risk. The RC has an incentive to communicate information that would protect the reliability of the system. There is no need for this time requirement on a forecasted EEA.	
Likes 0	

Dislikes 0	
Response	
Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	No
Document Name	
Comment	
Emergency procedures should be comprehensively covered under EOP-011 as noted in our response to Questions #9 and #11. To the extent notifications are retained for OPERAs, BAs and TOPs should share their Operating Processes directly with entities that have a role, similar to what is done under TOP-002-4, R3 and R5. There is no value added by requiring the RC to disseminate them. Likewise, BAs and TOPs should provide their plans to the RC (see TOP-002-4, R6-R7). If the RC notification requirement is retained, the SRC recommends that the language in R12 requiring the RC to notify neighboring RCs be revised to require the RC to notify neighboring RCs “within the same Interconnection.”	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
A. Based on BC Hydro’s understanding of the reliability need this proposed standard is trying to address, it would be adequately covered by EOP-011. B. The use of “Reliability Coordinator-reviewed” language in Requirement R11 is not required. The Requirement for a BA to submit is R8 and an RC to review is R9 and therefore the language in R11 is redundant. If it is kept, it implies that the BA won’t start implementing the Operating Process until R9.2 is met. As well, R11 isn’t clear of which Operating Process(s) is being referred to and if the “Reliability Coordinator-reviewed” language is kept, it could imply that any other Operating Processes developed under other Standards and referenced in R2 would also need to be RC reviewed prior to them being implemented. C. As well, it is not clear what the expectation is on the RC to resolve identified issues by the BA and does there need to be any closure after the initial notification by the RC. BC Hydro recommends clarifying. D. Under Requirement 12, it not clear what data will need to be shared between the BA(s) and RC(s) when the RC sends a notification. There does not seem like there is a need to share this info or data with other BAs or RCs. Should this need exist, BC Hydro recommends that data sharing agreements would be required to enable the exchange of relevant information with other BAs and/or RCs as appropriate.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not agree with the timeframe requirement for the RC to communicate a forecasted EEA. This would not add reliability benefits and would only serve to increase the RC's compliance risk. The RC has an incentive to communicate information that would protect the reliability of the system. There is no need for this time requirement on a forecasted EEA.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company supports the EEI comments and does not agree with the timeframe requirement for the RC to communicate a forecasted EEA.	
Likes 0	
Dislikes 0	
Response	
Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC	

Answer	No
Document Name	
Comment	
GSOC agrees that the RC should disseminate necessary information on a timely basis, but does not agree with the specific wording of these requirements. GSOC is supportive of the alternate language being submitted by Southern Company.	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
This is RC's responsibility. MH supports MRO NSRF's vote and comments for this one.	
Likes 0	
Dislikes 0	
Response	
Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	
Answer	No
Document Name	
Comment	
Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	

Comment	
Similar to our comments on R6, whether or not 24-hour notification to other BAs and entities is appropriate will depend on the timeframe of the OPERA and how far out the forecasted EEA is. Existing EEA notification processes should apply. It may not be appropriate or desirable for 24-hour notifications to occur if the potential EEA is forecast to occur days or weeks out, resource and load forecasts are variable and subject to change, and the entity has not yet had an opportunity to resolve the issues of concern in the normal course of business (through day-ahead or other energy purchases or other mechanisms).	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Emergency procedures should be comprehensively covered under EOP-011 as noted in our response to Questions #9 and #11. To the extent notifications are retained for OPERAs, BAs and TOPs should share their Operating Processes directly with entities that have a role, similar to what is done under TOP-002-4, R3 and R5. There is no value added by requiring the RC to disseminate them. Likewise, BAs and TOPs should provide their plans to the RC (*see* TOP-002-4, R6-R7).	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	

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	Yes
Document Name	
Comment	
We recommend making a minor modification to the language of the proposed Requirement R11. We suggest modifying R11 by using language comparable to R6: "Each Balancing Authority shall implement one or more Operating Processes, developed in accordance with R7, when a Near-Term OPERA forecasts an Energy Emergency Alert consistent with the scenarios developed in R2."	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNMR agrees that the language contained in Requirements R11 and R12 clearly define the responsibilities for both the BA and RC in the event of a forecasted Energy Emergency.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	

Answer	Yes
Document Name	
Comment	
Since this requirement has a different timeframe than EOP-011 R5, ISO-NE believes this requirement is appropriate.	
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 - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
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	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed the use of the term "Emergency notification" in Requirement R12. Is this intended to be the same as an Energy Emergency Alert as described in Attachment 1 of EOP-011-2? Perhaps the SDT should consider a NERC Glossary definition of Energy Emergency Alert. Texas RE also requests clarification on neighboring Reliability Coordinators as neighboring is not a defined term.	
Likes 0	
Dislikes 0	
Response	

13. Provide any additional comments for the SDT to consider, if desired.

Todd Bennett - Associated Electric Cooperative, Inc. - 1,3,5,6, Group Name AECI	
Answer	
Document Name	
Comment	
AECI appreciates the opportunity to provide informal comment on this draft standard. Based on SME feedback it appears this proposed standard is duplicative of current standards. TOP-002-4 currently includes requirements for the Balancing Authority to have Operating Plan(s) for the next-day that addresses expected generation resource commitment and dispatch, Interchange scheduling, Demand patterns, and Capacity and energy reserve requirements, including deliverability capability. R7-R12 of the new proposed standard are duplicative to the current EOP-011 standard which already requires coordination with the RC on potential energy or capacity shortages and emergencies along with emergency operating plans and actions. The draft approach may provide minimal improvement to reliability and signifigant additional regulatory administrative burden.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	
Because the standard is not applicable to the TOP and consists of energy assurance, this standard should be located within the BAL standard set, not the TOP standard set. Alternatively, the standard could be placed within the IRO standard set applicable to RCs, since the RC is also listed as one of	

the applicable registered entities. The current proposed placement within the TOP standard set creates the opportunity for confusion, which can easily be mitigated by choosing one of the two standard sets applicable to the BA or RC, respectively.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

Overall, the MRO NSRF supports the concept of performing Energy Reliability Assessments; however, we believe there are several structural items that need work in the proposed draft:

I. The standard lacks purpose and a Purpose statement. It is unclear what risk the standard is attempting to address.

The Purpose statement needs to clearly articulate what additional reliability benefits will be achieved as a result of implementing this standard. At this time, it is unclear whether there would be any additional benefits over existing processes. If the focus of this standard is the BA, what BA functions are we seeking to address (e.g. adequacy of reserves, frequency response, etc.)? Further, if we find resources are insufficient, what additional actions can be taken in an Operations Planning horizon? If the focus is solely on the BA, why is this standard in the TOP family and not the BAL family of standards?

Without a clear objective, the standard meanders over the entire operations spectrum and spends too much time dictating “how” OPERAs are to be performed and little time on what benefits will be achieved. In addition, it is unclear whether the intent of this standard is to retire the Operating Plans required under TOP-002-4 (R1 and R4) in favor of OPERAs once this project is complete. If not, the SDT should clearly articulate how OPERAs differ from OPAs and what risk OPERAs address beyond that of OPAs.

For example: Each scenario involving an energy contingency could include a simple energy accounting: how much energy is lost in the time period, what resources are expected to replace it, is the replacement energy and associated fuel available, and is the resulting capacity factor of the replacement or marginal resources highly achievable?

II. The natural progression of existing standards should be preserved: seasonal assessments, OPERAs (TOP-XXX-X), OPAs (TOP-002), RTAs (TOP-001) and emergency procedures (EOP-011).

The MRO NSRF’s understanding is the intent of the OPERA is to bridge seasonal assessments and Operating Plans (OPAs) pursuant to TOP-002. The MRO NSRF notes that *no* time horizon is currently listed in proposed standard TOP-XXX-X, requirement R1 which also contributes to a lack of clarity. In terms of time horizon, following is the order of standards (in decreasing lead time to real-time):

- Seasonal assessments - seasonal to one year out
- **TOP-XXX: Operations Planning Energy Reliability Assessments (OPERAs) -** 7 day to one month look ahead
- **TOP-002:** Operating Planning Analysis (OPAs) and Operating Plans (OP) - Next Day
- **TOP-001:** Real-Time Assessments (RTAs) - Real-time; normal operations
- **EOP-011:** Emergency procedures - Real-time; emergency operations

Recommendation: The SDT should consider how OPERAs fit into the overall Operations Planning horizon, clearly define the goal of OPERAs and articulate what risk they address. Then write requirements to achieve the stated goal. OPERAs should feed into the OPA process and not leapfrog OPAs and RTAs by moving directly into emergency procedures. If there are inadequacies in EOP-011, they should be addressed in EOP-011.

III. The standard is written from a Control Area perspective, assigning all tasks to the Balancing Authority (BA), ignoring the role of the Transmission Operator (TOP). This needs to be fixed.

It is difficult to conceive how the Balancing Authority can prepare a multi-day look ahead OPERA that considers transmission usage, outages and contingencies that result in the loss of supply without the Transmission Operator (TOP) performing a parallel analysis. At a minimum, the TOP should evaluate System Operating Limits (SOLs) to ensure they are not exceeded in the OPERA.

IV. The standard fails to require Generator Operators (GOPs) to provide the necessary data (over the Study Period) to perform the OPERA. This needs to be fixed.

To the extent TOP-XXX requires BAs (and TOPs) to consider generator specific factors such as: fuel supply and inventory, consumable fuels, environmental constraints, emission limits, etc., in preparing its OPERA, TOP-XXX *must* also include a corresponding requirement for Generator Operators (GOP) to provide the BA and TOP with this information for the time horizon required.

V. To ensure consistency across OPERAs in an efficient manner, the Reliability Coordinator (RC) should develop an OPERA methodology (as done in FAC-011) that would be distributed and followed by the BAs and TOPs in its RC footprint.

If the SDT retains the scope of the OPERA, the RC should develop an OPERA methodology to be used by the BAs and TOPs in its footprint. This would eliminate the need for Table 1 in the standard and go along way in ensuring consistency and coordination akin to **System Operating Limits Methodology for the Operations Horizon** (**FAC-011-4, R9**). If the RC were to develop this it would allow for more flexibility with the OPERAs.

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 supports the concept of performing ERAs. However, Tacoma Power is concerned on the overlap between the new Requirements and the existing Requirements in TOP-002-4 and EOP-011-3. As outlined in this posting, the OPERA could satisfy the OPA Requirements. Additional information is needed in a technical rationale or implementation guidance to understand the difference between the OPA TOP-002 Requirements and the proposed OPERA.

Tacoma Power also supports the comments from MRO NSRF.

Likes 0	
Dislikes 0	

Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
Near-term reliability planning is critical and undertaken today by entities even without this standard. While improvements can always be made, the incremental benefit of the improvement should also be considered. The standard appears to impose broad requirements without recognition of regional or local facts and circumstances. Resources should be focused on addressing high-risk seasons or periods, without requiring significant additional workload in lower-load, lower-risk periods. While events can still happen in those periods, the standard should balance the risk with the additional effort required, particularly given other existing requirements and processes.	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA supports the concept that entities ensure that they have energy assurance and thanks the SDT for their work on this standard. BPA agrees that while BAs should determine whether their load profile will be able to be served reliably from generators and imports, deliverability is critical for ensuring reliability. BPA proposes language updates above for the SDT's consideration to make the purpose and requirements more clear. BPA would like to request the SDT discuss whether it is possible for this standard to not be part of the Reliability Standard Family for Transmission Operations (TOP). BPA thinks it would be a better fit as a BAL standard (or maybe a MOD standard). While standards in the TOP Reliability Standard Family do have BA requirements, they are predominantly for the Transmission Operator and this standard is only for the BA (and RC). The type of assessment outlined in this standard is less a power flow type study and more energy assurance and deliverability (transmission rights) evaluation. As written, this standard would allow a BA to look out over the course of an entire month (with no requirement for reassessment weekly). Looking out an entire month (without required reassessment) is not ensuring reliability due to the quality of data available that far ahead of time. BPA believes a weekly assessment is more appropriate and would provide real value. If the desire is to look out beyond a week, consider looking at a study resolution of a daily assessment.	
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	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE strongly encourages the drafting team to provide a sample timeline, illustrating all timeframes in the requirements and how they all work together. Texas RE is concerned there may be an assessment based on a process that may not cover all the Real-time issues (how many wind plants lose "fuel" and what impact does it have on an Operating Process). If a BA has to change an Operating Process to contain a reliability risk, it may not have time for review by the RC. This could lead to the industry not having a paper trail that covers any issue and when it does not in Real-time there will be compliance consequences.	
Likes 0	
Dislikes 0	
Response	

Nikki Carson-Marquis - Minnkota Power Cooperative Inc. - 1 - MRO	
Answer	
Document Name	
Comment	
Minnkota Power Cooperative supports comments by the MRO New Standards Review Forum (MRO NSRF) and ACES.	
Likes 0	

Dislikes 0	

Response

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	

We agree with MRO NSRF's comments that this standard is lacking of purpose statement and clarification of the different scope with other standards. Please refer to MISO's comments for more details.

Likes 0	
Dislikes 0	

Response

Jason Snodgrass - Georgia System Operations Corporation - 3 - SERC	
Answer	
Document Name	
Comment	

GSOC is generally supportive on an Energy Reliability Assessment standard, but believes the proposed standard as written is overly burdensome. GSOC is supportive of the alternate language being submitted by Southern Company.

Likes 0	
Dislikes 0	

Response

Leslie Burke - Southern Company - Southern Company Generation - 5,6, Group Name Southern Company	
Answer	
Document Name	TOP-0XX_ERA__redline_SOCO1.docx
Comment	

Southern Company supports the comments submitted by EEI and the proposed language changes to R1 provided in Question 2 and would go a step further to state that the language as put forward by EEI in R1.3 would provide for all needed ERAs in the Operations Planning Horizon. This language would include assessments for both the Next Day (near real-time) and Seasonal (upcoming season) time periods.

Southern Company also supports the EEI stance in Question 5 that Table 1 should not be included in the proposed standard. The proposed language changes to R1 provided by EEI in Question 2 provide enough direction to define how and when the ERA will be performed by the BA in R1.3.

In addition to supporting the EEI comments in Questions 6 through 12, Southern is including additional proposed language to aid the SDT. We believe these revisions will reduce the compliance burden on the RC while effectively supporting their need to review the BA ERA Processes and remain informed of relevant ERA results. **See the attached documentation**.

Please email pdburns@southernco.com for any questions regarding these comments.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	
Document Name	

Comment

We support the project.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	TOP-0XX Energy Reliability Assessment ISO-NE edits 10-3-2023 Clean Redline.docx

Comment

Is a TOP Standard appropriate for this?

1. TO/TOP entities are not included in the Applicability Section.

2. This would be the only TOP Standard that would include the RC Function as an Applicable Entity.

3. Would this be better suited in a new EOP Standard?

a. The Standard is referenceing Forcasted Energy **Emergencies**,

b. This is applicable to **BAs** and **RCs,**

c. **RCs** are not in applicable section of any BAL Standards, and

d. This Standard is already modeled after EOP-011.

ISO-NE is submitting a redline version of TOP-0XX in its response to Question 13.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Ameren agrees with and supports MISO's comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI offers the following additional comments for consideration:

The proposed draft standard introduces unnecessary definitions and requirements that are duplicative with existing standards. As such, we are providing modifications with explanations to assist the standard drafting team.

The Energy Reliability Assessment standard should be drafted in a manner that gives flexibility for regional needs and gives deference to entities with the appropriate knowledge and experience of the systems within their control. Any process performed pursuant to the standard should only be performed when necessary to enhance reliability.

Propose changing the name of this standard to (in boldface): "**Operations Planning** Energy Reliability Assessment**s**"

The inconsistent use of "study duration" and "study horizon" should be standardized in the next version of this proposed standard.

The language in this standard more closely aligns with a BAL Standard, not a TOP Standard. The STD should consider changing this to a BAL standard or possibly adding these requirements to EOP-011. Alternatively, the requirements in the proposed TOP standard could be split between a BAL and EOP to mirror the current relationship between TOP and EOP standards for existing Transmission Operations Planning assessments.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5, Group Name BC Hydro

Answer	
Document Name	

Comment

A. R1, R2, R7, R11 include references Reliability Coordinator-reviewed language. This increases the BA risk of noncompliance against R1, R2 and R7 should the RC fail to perform their review. There are specific Requirements for the BA to submit R1 process and R2 scenarios/method of development to the RC in R3, and same for R7 to be submitted by the BA to the RC in R8. Therefore BC Hydro recommends removing the Reliability Coordinator-reviewed language from R1, R2 and R7. This will ensure clear measures for compliance.

B. The proposed standard appears too granular and prescriptive with no clear justification on the specific improvements to grid Reliability. Specific regions may have specific facts and circumstances that may inform the frequency of assessments and the length of time period being assessed; there should be flexibility to be customizable based on an entity's circumstances. If specific areas of the NERC footprint would benefit from such an approach, it may be better to address those regional concerns through other means than a Standard.

C. Additionally, the amount of time provided for comment was too short to be able to provide in-depth feedback. Given the large number of proposed changes, BC Hydro would recommend that more time be allowed for Standards with significant changes/new definitions/etc. and that industry webinars be conducted to discuss the proposed changes and allow a more interactive platform to provide comments and gain clarity.

D. BC Hydro also notes that the Questions seem to provide further interpretation of the Definitions and Standard that would be lost once the Standard is finalized. Also, it is confusing to try to understand all the timeline expectations for the study periods versus study frequencies. BC Hydro recommends developing technical justification/rationale/guidance to support the Standard Requirements and including a sample/generic timeline showing the Study Period/Duration/Frequency to help visually understand and tie the definitions with the Standard Requirements.

Likes 0	
Dislikes 0	

Response

Harishkumar Subramani Vijay Kumar - Independent Electricity System Operator - 2, Group Name IRC SRC

Answer	
Document Name	

Comment

The SRC believes there are several structural items in the proposed draft that would benefit from further refinement: I. The standard lacks purpose and a purpose statement. It is unclear what risk the standard is attempting to address. Without a clear objective, the standard meanders over the entire operations spectrum and spends too much time dictating how OPERAs are to be performed and little time on what benefits will be achieved. In addition, it is unclear whether the intent of this standard is to retire the Operational Planning Analysis and next-day Operating Plans required under TOP-002-4 (R1 and R4) in favor of OPERAs once this project is complete. If not, the SDT should clearly articulate how OPERAs differ from OPAs and what risk OPERAs address beyond what OPAs address. Additionally, as the standard is currently drafted, the SRC has identified several factors that will significantly diminish the accuracy and usefulness of the Near-Term OPERA, and the SRC is uncertain what actions a BA would be able to take to mitigate a forecasted Energy Emergency that a BA cannot already take under existing NERC Reliability Standards and with the tools already available to it. The SRC requests that the SDT address these issues, either by revising the draft standard or by providing additional information in the technical rationale or implementation guidance. II. The natural progression of existing standards should be preserved: seasonal assessments, OPAs (TOP-002), RTAs (TOP-001), and emergency procedures (EOP-011). The SRC's understanding is the intent of the OPERA is to bridge seasonal assessments and Operating Plans (OPAs) pursuant to TOP-002. The SRC notes that no time horizon is currently listed in proposed standard TOP-XXX-X, requirement R1, which also contributes to a lack of clarity. In terms of time horizon, following is the order of standards (in decreasing lead time to real-time): • Seasonal assessments - seasonal to one year out • TOP-XXX: Operations Planning Energy Reliability Assessments (OPERAs) - 7 day to one month look ahead • TOP-002: Operating Planning Analysis (OPAs) and Operating Plans (OP) - Next Day • TOP-001: Real-Time Assessments (RTAs) - Real-time; normal operations • EOP-011: Emergency procedures - Real-time; emergency operations Recommendation: The SDT should consider how OPERAs fit into the overall Operations Planning horizon, clearly define the goal of OPERAs and articulate what risk they address, then write requirements to achieve the stated goal. OPERAs should feed into the OPA process and not leapfrog OPAs and RTAs by moving directly into emergency procedures. If there are inadequacies in EOP-011, they should be addressed in EOP-011. III. The standard is written from a Control Area perspective, assigning all tasks to the Balancing Authority (BA), ignoring the role of the Transmission Operator (TOP). This needs to be fixed. It is difficult to conceive how the Balancing Authority can prepare a multi-day look ahead OPERA that considers transmission usage, outages, and contingencies that result in the loss of supply without the Transmission Operator (TOP) performing a parallel analysis. At a minimum, the TOP should evaluate System Operating Limits (SOLs) to ensure they are not exceeded in the OPERA. IV. The standard fails to require Generator Operators (GOPs) to provide the BA the necessary data (over the Study Period) to perform the OPERA, and it is not clear that data of sufficient quality is available over the timeframes contemplated in the standard. Regarding the Near-Term OPERA, requirement R1, part 1.1.4 contemplates a Study Duration of at least seven days, while part 1.1.3 contemplates a Study Temporal Resolution of one hour. The SRC has already addressed the ambiguity of the Study Duration in its response to question 2 above, and is concerned that the draft standard does not appear to provide a mechanism for the BA to obtain the high-quality input data that would be necessary for a 7-day study to produce accurate and useful results. Performing such a study would require additional data from generation units, such as: fuel supply and inventory, consumable fuels, environmental constraints, emission limits, etc. Any requirement for a BA to prepare an OPERA must also include a corresponding requirement for Generator Operators (GOP) to provide the BA and TOP with this information for the time horizon required. Compounding this issue, it is the SRC's experience that information regarding expected generator performance, and particularly information regarding expected fuel supply constraints, is rarely accurate more than one or two days in advance of the operating day, if it is even available at all. This is due in part to the need for the day-ahead market to solve before generators can know what will be required of their units and for the BA to know if it will need to commit additional units to maintain reliability. Attempting to forecast Energy Emergencies seven days out with limited input data would likely result in a large number of false positives. These considerations, combined with the resource-intensive nature of a seven-day study with a one-hour temporal resolution, mean that the value of the Near-Term OPERA results may not justify the resources required to perform the assessment. V. To ensure consistency across OPERAs in an efficient manner, the Reliability Coordinator (RC) should develop an OPERA methodology (as done in FAC-011) that would be distributed and followed by the BAs and TOPs in its RC footprint. If the SDT retains the scope of the OPERA, the RC should develop an OPERA methodology to be used by the BAs and TOPs in its footprint. This would eliminate the need for Table 1 in the standard and go a long way towards ensuring consistency and coordination akin to the System Operating Limits Methodology for the Operations Horizon (FAC-011-4, R9). VI. The reliability benefit of the proposed standard is unclear. Finally, it is unclear what additional tools would be available to a BA to mitigate any forecasted Energy Emergencies compared to the tools that BAs already use. Fuel supply issues, just like other factors that impact generator capabilities, already result in outages or derates being entered in the BA's outage scheduler, and BAs already have the tools and procedures to address unit outages and derates. Even if the BA had additional advanced notice of a fuel supply-related outage or derate, the BA does not have the ability or the authority to involve itself with fuel supply contracts and deliverability issues. Additional advance notice also would not impact the BA's ability to commit a unit for reliability, since the day-ahead market would still need to solve before reliability commitments could be used. Consequently, it is unclear to the SRC what overall benefit would result from the Near-Term OPERA as proposed, and the SRC requests that the SDT revise the draft standard to address this concern and the other concerns the SRC has identified.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	

Document Name	
Comment	

PNMR supports EEI's comments for question 13:

Propose changing the name of this standard to (in boldface): "**Operations Planning** Energy Reliability Assessment**s**"

Throughout the Standard it mentions the "Time Horizon: Operations Planning" yet the Standard never defines what the Time Horizon actually is in the context of this Reliability Standard. (Ref. R3, R7, R8, R12)

The language in this standard more closely aligns with a BAL Standard, not a TOP Standard. The STD should consider changing this to a BAL standard.

Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	
Comment	

AZPS has not additional comments.

Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	
Comment	

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

Likes 0	
Dislikes 0	
Response	

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	

Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute for questions #13.	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD	
Answer	
Document Name	
Comment	
This new standard expresses the good and necessary intention for BAs to evaluate resources and loads for forecasted emergencies. However, these 12 requirements are duplicate and unnecessary studies/assessments/reviews for BAs and RCs.	
Likes 0	
Dislikes 0	
Response	

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

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022

Anticipated Actions	Date
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024
Formal or informal comment period with additional ballot	May 2024
Final ballot	August 2024
Board adoption	December 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) - Evaluation of the resources that supply electrical energy and ancillary services for the Bulk Power System to reliably meet the expected demand during the associated time period. ERAs account for the impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).

A. Introduction

1. **Title:** **Energy Reliability Assessments**
2. **Number:** **BAL-007-1**
3. **Purpose:** To assess and mitigate the risks of energy emergencies in the operations planning time horizon by analyzing the expected resource mix availability and the expected availability of fuel during the study period.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
     - **4.1.2.** Reliability Coordinator
5. **Effective Date:** See Implementation Plan
6. **Background:** See Project 2022-03 project page

B. Requirements and Measures

R1. Each Balancing Authority shall document and maintain a Reliability Coordinator-reviewed Energy Reliability Assessment (ERA) process, which shall be reviewed at least annually and updated, if necessary. The ERA process document shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. Identify the frequency and duration of the ERAs with a corresponding rationale for each following time horizons:

1.1.1. Near-term; and

1.1.1.1. The end of the near-term assessment period shall be greater than five days and less than six weeks from the start of the assessment.

1.1.1.2. Each subsequent near-term assessment period shall partially overlap the previous near-term assessment period.

1.1.2. Seasonal;

1.1.2.1. Seasonal ERAs shall be performed for a minimum of two seasons that is representative of seasonal risks for operations.

1.1.2.2. Document a deadline for completing each seasonal ERA based on mitigation options for each seasonal ERA.

1.2. Include a process for the development of the base case that includes, but is not limited to, the following up-to-date data:

1.2.1. Time series demand;

1.2.2. Demand response, as appropriate;

1.2.3. Generator capability considering known constraints of:

1.2.3.1. Availability, including planned outages, and flexibility;

1.2.3.2. Fuel supply and inventory concerns;

1.2.3.3. Fuel switching capabilities; and

1.2.3.4. Environmental constraints.

1.2.4. Documented energy transfer assumptions; and

1.2.5. Energy storage capability.

1.3. Include a documented rationale for the base case elements chosen in Requirement R1.2.

M1. Each Balancing Authority shall have evidence of a process document and maintained in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed ERA scenarios for both the near-term and seasonal time horizons, as follows: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Each set of ERA scenarios shall include:

2.1.1. Projected system load for the interval being studied with system normal (no contingency) conditions;

2.1.2. Projected system load for the interval being studied with an energy contingency as described in Attachment 1;

2.1.3. Projected system load for the interval being studied with fuel supply contingency as described in Attachment 1;

2.1.4. High load for the interval being studied with system normal (no contingency) conditions;

2.1.5. High load for the interval being studied with energy contingency as described in Attachment 1;

2.1.6. High load for the interval being studied with fuel supply contingency as described in Attachment 1; and

2.1.7. If appropriate for the seasonal time horizon, a scenario(s) with a likely event of occurring within the interval being studied that may include seasonally appropriate historical events, generation specific fuel or energy contingency scenarios, and weather events that are projected to occur if appropriate for the seasonal time horizon only.

2.2. The Balancing Authority shall document the rationale for the scenarios identified in Requirement R2.1.

M2. Each Balancing Authority shall have evidence that scenarios were developed and maintained along with a documented rationale and criteria in accordance with Requirement R2. Such evidence could include, but is not limited to, e-mail records or review or revision history to indicate that the scenarios, rationale, and criteria have been documented.

R3. Each Balancing Authority shall develop, maintain, and document one or more Operating Plan(s) to mitigate unacceptable risk(s) associated with ERA scenario(s) with a likely event of occurring. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it developed, maintained, and documented its Operating Plan(s) in accordance with Requirement R3. Such evidence could include, but is not limited to, a review or revision history to indicate that the Operating Plan(s) have been developed, maintained, and documented.

R4. The Balancing Authority shall submit the following information to its Reliability Coordinator for review on a mutually agreed-upon schedule: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

4.1. The ERA process;

4.2. The ERA scenarios; and

4.3. Operating Plan(s).

M4. Each Balancing Authority shall have evidence that it submitted the information to its Reliability Coordinator on a mutually agreed upon schedule in accordance with Requirement R4. Such evidence could include, but is not limited to, e-mail records.

R5. Within 60 calendar days of receipt of the information identified in Requirement R4, the Reliability Coordinator shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

5.1. Review each submittal for coordination with other Balancing Authorities' ERA information to avoid risks to Wide Area reliability; and

5.2. Notify each Balancing Authority of the results of its review, and if the need for revisions is identified, to address any reliability risks.

M5. Each Reliability Coordinator shall have evidence that it reviewed each submittal with other Balancing Authorities' ERA information to avoid risks to Wide Area reliability and notify each Balancing Authority of the results of the review in accordance with Requirement R5. Such evidence could include, but is not limited to, e-mail records.

R6. Within 60 calendar days of receipt of the Reliability Coordinator's notice of the results of the review conducted under Requirement R5, each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit the updated information required in Requirement R4 to its Reliability Coordinator, unless otherwise specified by its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have evidence that it addressed any reliability risks identified by its Reliability Coordinator within 30 calendar days or as specified by its Reliability Coordinator in accordance with Requirement R6. Such evidence could include, but is not limited to, e-mail records.

R7. Each Balancing Authority shall perform ERAs according to the process documented in Requirement R1 using the scenarios documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it performed the ERA in accordance with Requirement R7. Such evidence could include, but is not limited to, dated ERA results.

R8. Each Balancing Authority shall determine energy reserve margins calculated for each time step of an ERA scenario according to the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

8.1. For the ERA scenarios identified in Requirement R2.1.1 and Requirement R2.1.4, the energy reserve margin is at least 150% of the largest N-1 Contingency within each Balancing Authority's footprint plus at least 2% of the load forecast for the near-term ERA or at least 5% of the load forecast for the seasonal ERA;

8.2. For the ERA scenarios identified in Requirement R2.1.2 and Requirement R2.1.5, the energy reserve margin is at least the larger of 150% of the largest N-1 Contingency within each Balancing Authority's footprint or 2% of the load forecast for the near-term ERA or at least 5% of the load forecast for the seasonal ERA; and

8.3. For the ERA scenarios identified in Requirements R2.1.3, Requirement R2.1.6, and Requirement R2.1.7, the energy reserve margin is at least 125% of the largest N-1 Contingency within each Balancing Authority's footprint.

M8. Each Balancing Authority shall have evidence that it determined an energy reserve margin in accordance with Requirement R8.

R9. Each Balancing Authority shall compare results of the ERA to the energy reserve margins in Requirement R8 and, if the energy reserve margins are not met, the Balancing Authority shall implement an Operating Plan(s) developed in Requirement R3. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

M9. Each Balancing Authority shall have evidence that it implemented an Operating Plan(s) when the required reserve margin was not met in accordance with Requirement R9.

R10. Each Balancing Authority shall provide the results of the ERA and the comparison of results from Requirement R9 to its Reliability Coordinator under the following conditions: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

10.1. The ERA comparison to the energy reserve margin requires implementation of an Operating Plan(s) to mitigate risk within 24 hours for the near-term time horizon or;

10.2. The ERA performed is a seasonal ERA within 14 calendar days or;

10.3. The Reliability Coordinator has requested the results.

M10. Each Balancing Authority shall have evidence that it provided the results of the ERA to its Reliability Coordinator within the criteria in accordance with Requirement R10. Such evidence could include, but is not limited to, e-mail records.

R11. Each Reliability Coordinator that receives results of a near-term ERA and the comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 from a Balancing Authority within its Reliability Coordinator Area shall notify, within 24 hours from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of the implementation of an Operating Plan(s). *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M11. Each Reliability Coordinator will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or e-mail records that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R11, within 24 hours from the time of receiving results of a near-term ERA and the comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 from a Balancing Authority, other Balancing Authorities and Transmission Operators in its Reliability Coordinator area, and neighboring Reliability Coordinators of the implementation of an Operating Plan(s).

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Balancing Authority and Reliability Coordinator shall keep data or evidence to show compliance with applicable requirements for six months for near-term time horizon and 18 months for the seasonal time horizon or since the last audit.

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 Balancing Authority documented a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon but failed to maintain it at least annually. OR The Balancing Authority documented a Reliability Coordinator-reviewed Energy Reliability Assessment process for the seasonal time horizon but failed to maintain it at least annually.	The Balancing Authority documented and maintained a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon and seasonal time horizon but failed to include one of the required base case elements under Requirement R1 Part 1.2 or supporting rationale(s) under Requirement R1 Part 1.3 for the near-term time horizon or seasonal time horizon.	The Balancing Authority documented and maintained a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon and seasonal time horizon but failed to include two or more of the required base case elements under Requirement R1 Part 1.2 or supporting rationale(s) under Requirement R1 Part 1.3 for the near-term time horizon or seasonal time horizon. OR The Balancing Authority failed to document a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon. OR The Balancing Authority failed to document a

				Reliability Coordinator-reviewed Energy Reliability Assessment process for the seasonal time horizon.
R2	N/A	The Balancing Authority developed and documented Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon but failed to maintain them. OR The Balancing Authority developed and documented Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the seasonal time horizon but failed to maintain them.	The Balancing Authority developed and documented Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon and seasonal time horizons but failed to include one of the scenarios of Requirement R2 Part 2.1 or supporting rationales under Requirement R2 Part 2.2 for the near-term time horizon or seasonal time horizon.	The Balancing Authority developed and documented Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon and seasonal time horizons but failed to include two or more of the scenarios of Requirement R2 Part 2.1 or supporting rationales under Requirement R2 Part 2.2 for the near-term time horizon or seasonal time horizon. OR The Balancing Authority failed to develop or document Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon. OR The Balancing Authority failed to develop or

				document Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the seasonal time horizon.
R3	N/A	N/A	N/A	The Balancing Authority failed to develop an Operating Plan(s) to mitigate risk identified in the Energy Reliability Assessments.
R4	N/A	N/A	The Balancing Authority submitted information that contained the Energy Reliability Assessment process, the Energy Reliability Assessment scenarios, and Operating Plan(s) but failed to submit within the mutually agreed-upon schedule.	The Balancing Authority failed to submit information that contained the Energy Reliability Assessment process, the Energy Reliability Assessment scenarios, and Operating Plan(s).
R5	N/A	N/A	The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' Energy Reliability Assessment information to avoid risks to Wide Area reliability but failed to notify	The Reliability Coordinator failed to review each submittal for coordination with other Balancing Authorities' Energy Reliability Assessment information to avoid risks to Wide Area reliability.

			each Balancing Authority within 60 calendar days.	
R6	N/A	N/A	The Balancing Authority addressed any reliability risks identified by its Reliability Coordinator and resubmitted the updated information required in Requirement R2 to its Reliability Coordinator but failed to resubmit the updated information within 60 calendar days of receipt or as specified by its Reliability Coordinator.	The Balancing Authority failed to address any reliability risks identified by its Reliability Coordinator. OR The Balancing Authority failed to resubmit the updated information required in Requirement R2 to its Reliability Coordinator.
R7	N/A	N/A	N/A	The Balancing Authority failed to perform Energy Reliability Assessments in accordance with its process documented in Requirement R1 using the scenarios documented in Requirement R2.
R8	N/A	N/A	N/A	The Balancing Authority failed to determine the energy reserve margins in accordance with Requirements R8 Parts 8.1 through 8.3.

R9	N/A	N/A	N/A	The Balancing Authority compared results of the Energy Reliability Assessment to the energy reserve margins in Requirement R8 but failed to implement an Operating Plan(s) developed in Requirement R3 upon determining the energy reserve margins were not met. OR The Balancing Authority failed to compare results of the Energy Reliability Assessment to the energy reserve margins in Requirement R8.
R10	N/A	N/A	N/A	The Balancing Authority failed to provide the results of the Energy Reliability Assessment to its Reliability Coordinator when any of the conditions listed in Requirement R10.1 – R10.3 are met.
R11	The Reliability Coordinator received results of an Energy Reliability Assessment and comparison of results from Requirement R9	The Reliability Coordinator received results of an Energy Reliability Assessment and comparison of results from	The Reliability Coordinator received results of an Energy Reliability Assessment and comparison	The Reliability Coordinator received results of an Energy Reliability Assessment and

	pursuant to Requirement R10 Part 10.1 but notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators between 24-25 hours of receiving notification.	Requirement R9 pursuant to Requirement R10 Part 10.1 but notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators between 25-26 hours of receiving notification.	of results from Requirement R9 pursuant to Requirement R10 Part 10.1 but notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators between 26-27 hours of receiving notification.	comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 but notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators 27 hours or more of receiving notification. OR The Reliability Coordinator received results of an Energy Reliability Assessment and comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or one or more neighboring Reliability Coordinators.

D. Regional Variances

None.

E. Associated Documents

Implementation Plan

Version History

Version	Date	Action	Change Tracking
Version 1	TBD	Drafted by Project 2022-03 SDT	

BAL-007-1 Attachment 1

Energy contingency

The largest energy contingency is the loss of the largest energy supply (in MWh across the study duration) through either a generator or transmission outage caused by a single Contingency. The energy lost due to the largest energy contingency may not persist through the entire assessment period but assumes a likely duration as defined by the Balancing Authority for the Contingency.

The resource(s) can be identified through the normal load and high load scenarios identified in Requirements R2.1.1 and R2.1.4. The energy contingency resource(s) are the resource(s) that provides the most MWhs across the term of the study period and an N-1 Contingency can make that resource(s) unavailable.

Fuel contingency

The largest fuel contingency is the loss of fuel supply that causes the largest reduction in electrical energy supply (in MWh across the study duration). The fuel contingency does not have to occur for the entire assessment period but assumes a likely duration as defined by the Balancing Authority for the fuel contingency. The fuel sources to be considered should include pipelines, suppliers of consumable fuels, and variable sources like solar and wind energy.

The resource(s) can be identified through the normal load and high load scenarios identified in Requirements R2.1.1 and R2.1.4. The fuel contingency resource(s) are the resource(s) that provides the most MWhs across the term of the study period and a fuel contingency can make that resource(s) unavailable.

Examples of fuel contingencies include:

1. Loss of pipeline or gas compressor that limits output of or causes outages of multiple gas-fired generators.
2. Extended cloudy period that causes multiple days of low solar output.
3. Low water reservoirs that limit energy production from hydro facilities.
4. A single point of failure within a fuel (e.g., coal, diesel, hydrogen) delivery network.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2022-03 Energy Assurance with Energy-Constrained Resources
Reliability Standard BAL-007-1

Applicable Standard(s)

- BAL-007-1 – Energy Reliability Assessments

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Reliability Coordinator

Terms in the NERC Glossary of Terms

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

Proposed New Definition(s):

Energy Reliability Assessment:	Evaluation of the resources that supply electrical energy and ancillary services for the Bulk Power System to reliably meet the expected demand during the associated time period. ERAs account for the impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).

Background

Energy assurance is an increasingly important aspect of a reliable Bulk Electric System (BES) but has been inconsistently defined and measured without explicit standards. Project 2022-03 Energy Assurance with Energy-Constrained Resources was initiated to address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Reliability Standard BAL-007-1 – Energy Reliability Assessments is focused on the operations planning time horizons.

Effective Date and Phased-In Compliance Dates

The effective dates for proposed Reliability Standard BAL-007-1 and NERC Glossary term Energy Reliability Assessment are provided below. Where the standard drafting team identified the need for a longer implementation period for compliance with a particular section of a proposed Reliability Standard (i.e., an entire Requirement or a portion thereof), the additional time for compliance with that section is specified below. The phased-in compliance date for those particular sections represents the date that entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

Standard

Where approval by an applicable governmental authority is required, Reliability Standard BAL-007-1 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.

Compliance Date for BAL-007-1 Requirements R7-R11

Entities shall not be required to comply with Requirements R7 - R11 until six months after the effective date of Reliability Standard BAL-007-1.

Definition

Where approval by an applicable governmental authority is required, the definition of Energy Reliability Assessment 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 Reliability Standard BAL-007-1, 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 that Reliability Standard BAL-007-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Technical Rationale

Project 2022-03 Energy Assurance with Energy-Constrained Resources
Reliability Standard BAL-007-1 | January 2024

BAL-007-1– Energy Reliability Assessments

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard BAL-007-1. It provides stakeholders and the ERO Enterprise with an understanding of the technical requirements in the Reliability Standard. This Technical Rationale and Justifications for BAL-007-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Updates to this document include the Project 2022-03 Energy Assurance with Energy-Constrained Resources Standards Drafting Team's (SDT's) intent in drafting new requirements.

Overview

Project 2022-03 proposes a new Reliability Standard BAL-007-1 and the Energy Reliability Assessment (ERA) definition. The proposed Reliability Standard purpose is to address and mitigate the risks of energy emergencies in the operations planning time horizon by analyzing the expected resource mix availability and the expected availability of fuel during the study period. Unassured deliverability of fuel supplies, coincident with inconsistent output from variable energy resources and volatility in forecasted load, can result in insufficient amounts of energy available from the Bulk Electric System (BES) needed to serve electrical demand and ensure the reliable operation of the BES throughout each hour of the time period being evaluated. As part of ongoing operations planning, many entities have started incorporating some limited energy reliability assessments into reliability studies that produce key metrics; however there is inconsistency among entities and how the assessments are performed. To achieve the level of consistency needed across the industry, energy reliability assessments for the operations time horizon and the mitigation of identified risks are mandated and codified in this new standard.

Rationale for BAL-007-1

As the BES becomes more reliant upon energy constrained and variable resources, traditional capacity-based planning methods and strategies are being stretched and potentially not identifying energy-related risks to reliably operate and maintain the system. BAL-007-1 is being proposed as a step toward reducing these potential risks and to begin the transition to energy-based planning methods and strategies that incorporate critical time-based variables that are not captured in capacity-based processes. BAL-007-1 is intended to provide Balancing Authorities (BAs) and Reliability Coordinator (RCs) with the tools necessary to successfully navigate increasingly energy constrained and variable system operations. BAL-007-1 Operating Plans, while not intended to replace or supersede TOP-002 and/or EOP-011 Operating Plans, are intended to provide a list of actions implementable over a longer-term/earlier time period that can reduce the severity of or fully mitigate the need to implement TOP-002 and/or EOP-011 plans.

The new Reliability Standard can be separated into three basic activities:

- Developing and documenting ERA process, scenario, and Operating Plans (Requirements 1-6)
- Performing ERAs and comparing to Energy Reserve Margin (Requirements 7-8); and
- If Energy Reserve Margins are not met, implementing Operating Plan to mitigate energy reliability risks (Requirements 9-11)

The purpose of this standard is to assess energy risk in Operations Planning time horizon, determine if the risks are acceptable, and take actions to mitigate. This standard should improve reliability through identifying energy risk earlier and being able to implement longer lead time activities to mitigate those risks. The diagram below gives an overview of the process with actions and communication between entities outlined.

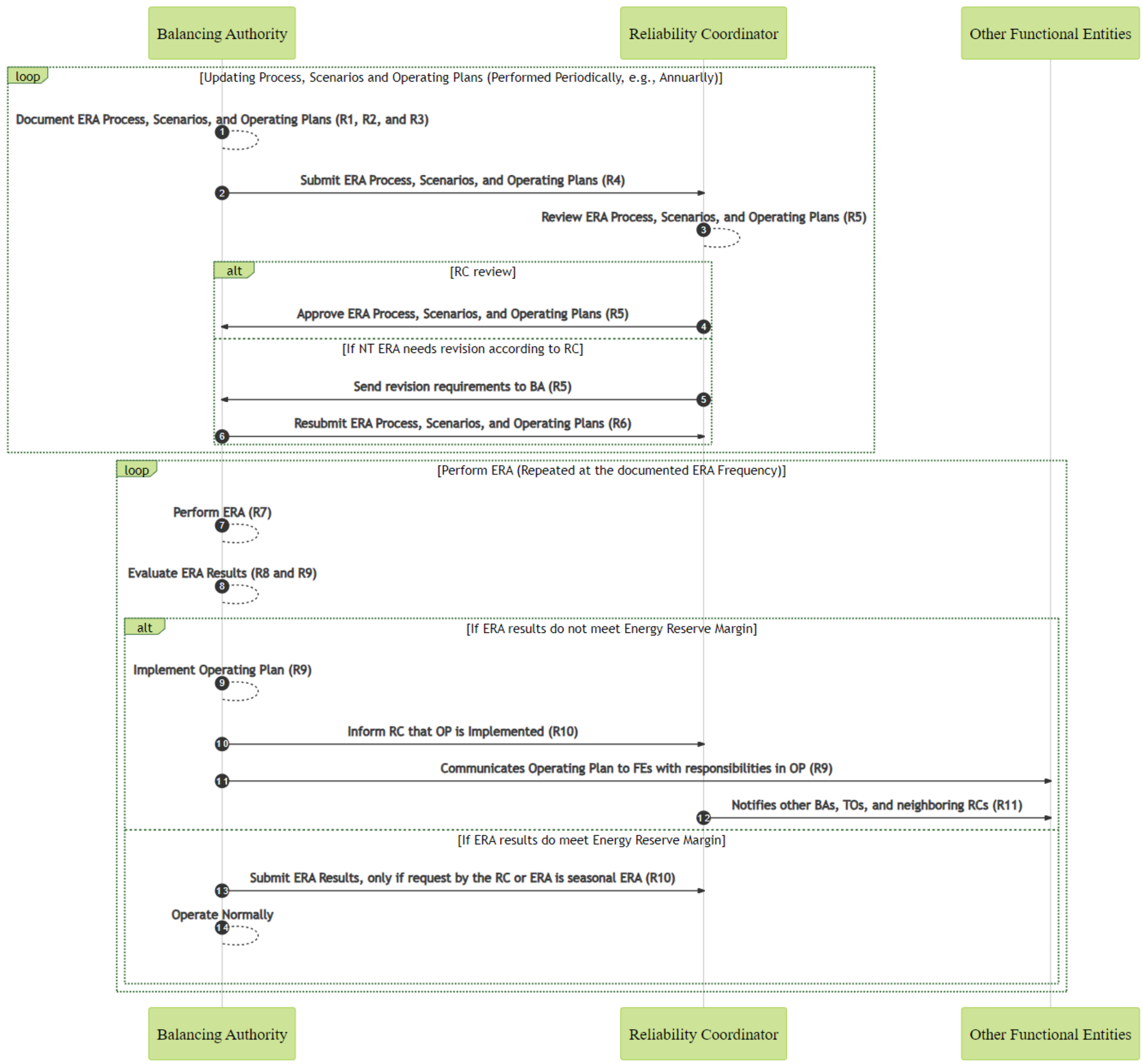

Figure 1. Process Diagram of ERA Requirements

Relationship to Other Standards

While the proposed standard has similarities to other standards, especially TOP-001, TOP-002, and EOP-011 standards, the proposed standard addresses reliability risks due to gaps in reliability standards by focusing on different time horizons than current standards and energy risks which are not clearly addressed. In many cases, the language is intentionally similar to language in those requirements but applicable to different time horizons. The BAL-007-1 standard looks at a near-term and a seasonal time horizon which is longer than other operations planning assessment requirements. In terms of addressing energy risks, BAL-007-1 more clearly outlines the assessment requirements to look at energy over an assessment period rather than capacity assessments generally used to comply with current standards.

TOP-001 and TOP-002 provide requirements for assessment and Operating Plans in real-time and operations planning time horizons, but their requirements are limited to less than one day ahead which limits the options that Balancing Authorities must respond. BAL-007-1's proposed language extends this outlook to greater than five days, so BAs have the time to implement mitigations actions with longer lead times (e.g., conserve consumable fuel, source additional fuel, reschedule outages) and have better situational awareness of potential reliability risks.

TOP-002, EOP-011, and BAL-007-1 all require Operating Plans to mitigate reliability risks, but they would be different in what actions are included in each. Since BAL-007-1 is assessing a longer time horizon, the projected conditions are more uncertain, and the Operating Plans developed under BAL-007-1 should reflect that. Instead of specifying specific steps that must be taken, the Operating Plan can have more general processes and incorporate longer lead time activities than Operating Plans in TOP-002. BAL-007-1 Operating Plans are not intended to replace TOP-002 and EOP-011 developed Operating Plans but to implement actions that can only be implemented when potential risks are identified with a longer lead time. The goal of these longer-term Operating Plans is to reduce the likelihood of an actual energy emergency occurring which would require an EOP-011 Operating Plan or at least, reduce the severity of the energy emergency. Actions in the BAL-007-1 Operating Plans should lead into the real-time and day-ahead Operating Plans rather than necessarily overlapping. This idea is similar between the seasonal and near-term ERAs; the seasonal assessments give situational awareness about a longer time horizon and allow for longer lead time activities which should reduce the risk of identifying risks in the near-term ERA. An example timeline of how BAL-007-1 and EOP-011 would interact is below when the BAL-002 associated Operating Plan is not sufficient to avoid an energy emergency. Ideally, the longer-term Operating Plan would result in the EOP-011 Operating Plan not being needed but if an energy emergency still occurs, the Operating Plans should reduce the severity of the energy emergency.

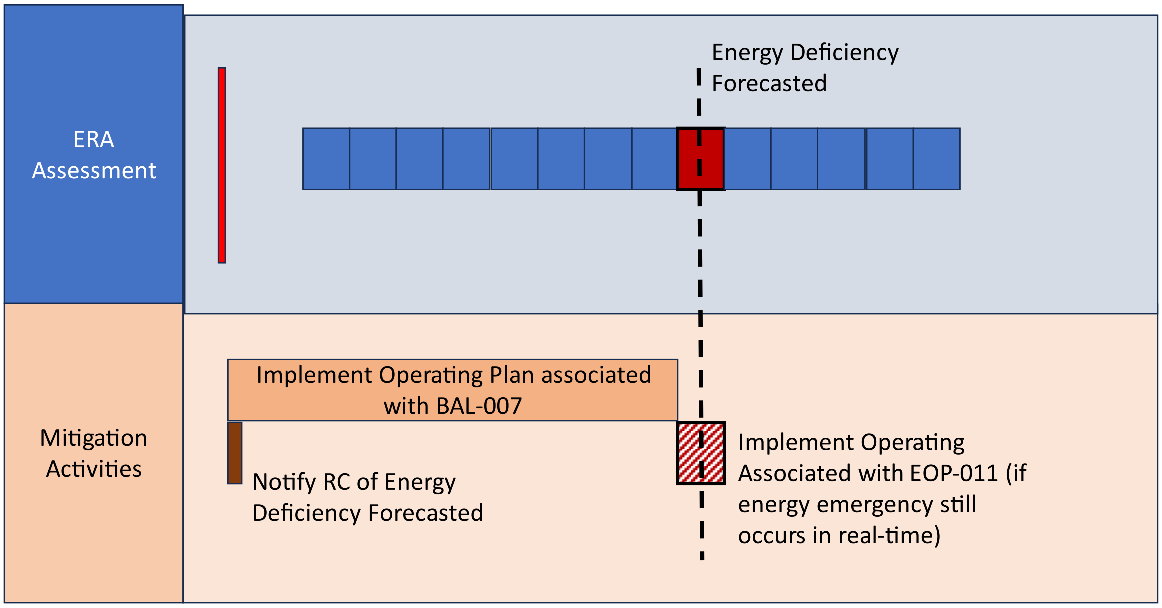

Figure 2. Timeline of ERA performance and Operating Plan Implementation if the forecasted energy deficiency is not fully mitigated when EOP-011 Operating Plan is still required.

Additionally, the BAL-007-1 assessments require considering energy risk which can only be performed by looking at an assessment over a period with multiple timesteps and considering stored energy and just-in-time energy sources. While TOP-002 Requirement 4 includes "energy reserve requirements" as a risk that Operating Plans must address, these assessments have generally been performed as capacity assessments which do not include the fuel risk especially over a longer period of time. The BAL-007-1 explicitly requires including these elements in an assessment and sets criteria regarding when risks need to be addressed through Operating Plans.

Requirement 1

Requirement 1 forms the basis for defining and requiring what ERAs are. Since ERAs are a new concept, more detail is needed in order to ensure that the intent is met. ERAs go beyond the existing scope of capacity assessments that have traditionally been performed. This intent begins with the work products generated by the NERC Energy Reliability Assessment Task Force (ERATF)[1] starting with the white paper (Ensuring Energy Adequacy with Energy Constrained Resources)[2], through the approval of the two Standard Authorization Requests (SARs) which handed the work off to the Standard Development Team

[1] Currently the Energy Reliability Assessment Working Group (ERAWG)
[2] https://www.nerc.com/comm/RSTC/ERATF/ERATF%20Energy%20Adequacy%20White%20Paper.pdf

(SDT) for Project 2022-03[3]. Requirement 1 is simply defining the minimum standards by which ERAs will be performed.

Requirement 1.1 starts the standard off with the definition of timelines for performing ERAs. Annual review of the process is intended to ensure that any changes in the resource mix or demand profiles are captured appropriately and intentionally. New resource types are being introduced into the power system routinely compared to years past. Each new resource comes with subtleties of how they perform and operate that may require an analyst to change the way they think about how the resources are portrayed in their energy reliability assessments. Events that occur on the system (e.g., droughts, storms, calm and cloudy stretches) will also change the basis of how an ERA is performed. As each year passes, a review of the ERA process will give some assurance that the ERA is useful and provides good data for system operators. There are two types of ERAs that are required in this standard. The first is near-term and the second is seasonal. Near term ERAs are intended to be performed on a routine basis and look at the time period that covers the next several days to weeks. Two-time horizons offer a different vantage point on a common timeframe (i.e., looking at the same week from a distance and again up close), resulting in different available actions that can be taken when issues are discovered, and more precision and accuracy when needed. Seasonal ERAs will tend to be more of a risk assessment with a wide array of possible conditions which a BA or RC can evaluate and begin to formulate actions that may take months to design, develop, and implement. Near-term ERAs will offer more precision and accuracy that offer a BA or RC enough detail to take specific actions, some of which are made possible because of the actions that were taken as a result of a seasonal ERA.

Requirement 1.1.1.1 outlines the minimum required time that an ERA must cover, between the next five days and the next six weeks. It is understood that every specific region will have a different set of concerns and risks. Some regions have a resource mix that makes for an ERA that extends past a few days unreasonable. Others may have longer term risks that require a longer assessment. For example, a region that is heavily dependent on long-lead-time fuel replenishment may need to look further into the near-term future (i.e., six weeks) in order to have the appropriate amount of time to react.

Requirement 1.1.1.2 requires an overlap between near-term ERAs, which will ensure that no period of time is left unassessed. Performing a two-week study every week will meet this requirement. Performing a six-week study every month will meet this requirement. The determination of how long to study will be based on several factors such as lead time to fuel replenishment or outage recall and accuracy of forecast information. The figure below gives an example of the timeline of performing near-term ERAs.

Seasonal ERAs are required to be performed at least twice per calendar year and look at the upcoming seasons, or representative samples of the season that would provide reasonable assurance that the expected conditions of the remainder of the season are understood. It is not requiring that a full 90-120 day season is included in an ERA, but does require that the BA performing the ERA document the rationale for why the time horizon and duration were selected.

[3] https://www.nerc.com/pa/Stand/Pages/Project2022-03EnergyAssurancewithEnergy-ConstrainedResources.aspx

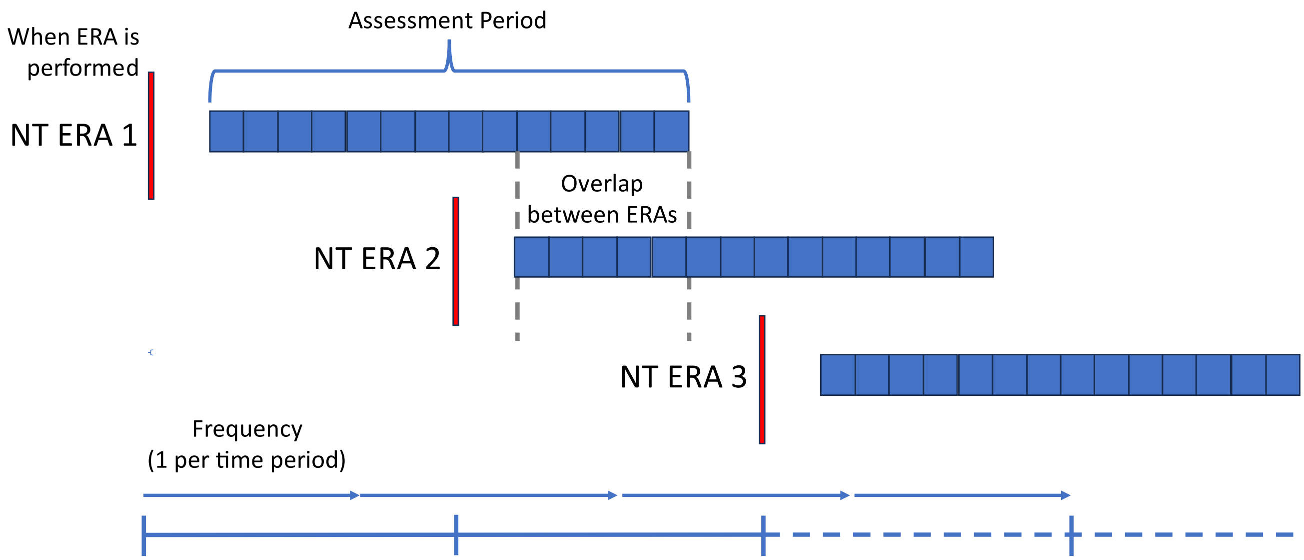

Figure 3- Timeline of performing multiple ERAs.

Requirement 1.2 sets a minimum amount of information that must be included in every ERA. This is not an all-inclusive list. If other parameters are necessary for a BA to fully model the energy landscape for the ERA, they should be included and documented with a rationale for selection.

Requirement 2

Requirement 2 outlines a minimum set of scenarios to be included in an ERA package. There are two basic sets of scenarios that form different combinations. Two load scenarios (projected and high) are expected to be similar to a 50/50, or expected load forecast and a high load forecast that would be something higher than that. High load scenarios would likely range between a 90/10 and maximum load scenario. There are then two, in effect, contingencies to be studied. The first is an energy contingency that removes the largest energy resource from the base case and runs it again. The other removes a set of resources that are supplied by the same fuel supply. This could be a natural gas pipeline but could also be a set of wind turbines that a closely situated where a storm could render them unavailable for a period of time or solar panels that could be covered by snow. Regardless of the chosen energy and fuel scenario, it is up to the BA to determine which resource or set of resources to include in the ERA and to document that decision along with a rationale per Requirement 2.2.

Requirement 3

Requirement 3 requires BAs to develop plans ahead of time to mitigate potential energy deficiencies identified through ERAs. These Operating Plans are developed so that in the event that an ERA shows that a BA will or may have insufficient energy (defined later), they will have an Operating Plan ready to implement, per Requirement 3. That Operating Plan is intended to be developed ahead of time so that it can be reviewed and updated before system conditions are unfavorable and be ready for later implementation. Operating Plans are expected to include actions that can be performed by the BA within the time horizon for which the ERA is designed. The actions that BAs may include in Operating Plans will also provide information to the BA regarding how long the assessment period of the ERA would need to be (Requirement 1.1) such that they can have time to accomplish the actions within. For example, if actions that could mitigate potential energy emergencies take two weeks to accomplish, the ERA should be looking at least two weeks into the future. Actions in an Operating Plan can be as simple as a set of prescribed notifications to a set of stakeholders that can impact the energy landscape to something as complicated as targeted load shed to save energy for when it is most needed. Ideally, actions could also include fuel replenishment, outage recall, arranging for imports from neighboring areas, and other actions that are specific to the region that would improve the supply/demand balance of energy.

As discussed in the comparison to other Standards section, the Operating Plans developed based on this requirement are not intended to supersede Operating Plans associated with TOP and EOP standards but include actions that will reduce the likelihood or severity of an energy deficiency occurring in real-time. To that end, the BA develops an appropriate Operating Plan for a potential energy shortfall that is identified by the ERA. Depending if the ERA is completed weeks or days prior to the energy shortfall, the BA decides on suitable plans to reduce the impact of an energy emergency. From prescribed notifications, load shed decisions, actions in an Operating Plan can be both simple and/or complex. Ideally, plans should include factors such as fuel replenishment, outage recall, importing from neighboring areas, and region-specific actions to enhance the energy supply/demand. Since the Operating Plans are being implemented based on assessments looking days to weeks ahead and the associated uncertainty of the results, BAs will likely not decide to include actions in the Operating Plans which would not need to occur until much closer to the projected event or only plan to implement those actions if the conditions projected ERA appear that they will still occur. For example, an Operating Plan may include increasing the frequency of performing ERAs in order to monitor whether the project energy emergency is more or less likely as the uncertainty of input data to the assessment decreases and other actions in the Operating plan have been implemented.

The ERA operating plans should be designed to be adaptable to unfolding conditions and proactive enough to avoid energy shortage by preparing ahead of time. As an example to illustrate the Operating Plan uses, when an ERA is performed two weeks ahead of a calculated shortfall then potential actions have a two-week timeline where identified risk conditions could change as well as two weeks to refine action plans. For instance, if ERA results during an extreme cold period that looks out two weeks determine the energy reserve margin may not be met, the BA's Operating Plan could include the following actions:

- Survey oil inventory of oil-fired generators and request generators with low inventory order more oil;
- Notify RC and relevant entities of the projected risk (e.g., Generator Operations, relevant government authorities, other BAs with expected imports or exports);
- Increase frequency daily performance of ERAs and assessing energy reserve margins and have Operating Plan actions conditional on the risk;
- Conserve consumable fuels for period with projected energy shortfall; and
- If ERA results still indicate unacceptable risk of energy deficiency two days prior to projected event, instruct thermal plants to warm up leading up to event to avoid outages due to ice formations and cold-start issues.

Ideally, these actions will prevent an energy emergency occurring in real-time. However, if the energy emergency still occurs, these actions should reduce the energy deficiency and prepare the BAs to implement an emergency Operating Plan. This scenario is intended only to be one simple illustrative example that does not reflect all potential Operating Plan actions or actions that BAs in all regions can do.

Requirement 4

Requirement 4 provides a channel of communication between a BA and their associated RC. Requirement 4 is simply a BA providing their ERA, as defined by R1, R2, and R3 to the RC. The BA and the RC shall develop a mutually agreed-upon schedule for when the BA shall submit this information to the RC. Note that the ERA has not yet been performed, but only designed. Due diligence during this design phase requires the BA to identify the risks that could lead to an energy shortfall in the near-term and/or seasonal timeframe. The design, along with the base case, scenarios, and Operating Plan(s) are all part of the package that is provided to the RC.

Requirement 5

Providing ERA information to the RC under Requirement 4 is paired with Requirement 5 for the RC to review that package within 60 days of receipt. The RC review is intended to identify risks to Wide Area reliability and ensure all identified risks are communicated to the BA. Coordination is required to ensure that there are no conflicting assumptions between BAs. Once a review is complete, the RC notifies the BA, and any necessary changes occur within Requirement 6. For example, an assumption by two BAs sharing a common transmission interface of an import condition from the other BA during the same time period would result in an infeasible allocation of energy resources and would trigger an RC notification. The RC review provides additional reliability benefits by comparing the BA’s ERA information to that of other BAs, allowing for identification and mitigation of discrepancies and/or opportunities for enhancements to strengthen the contents of a BA’s ERA package.

Requirement 6

Requirement 6 is the third part of the communication between the RC and BA where the BA is required to address issues identified by the RC and resubmit the ERA process, ERA scenarios, and Operating Plan(s). This requirement ensures the closing of the communication loop and documentation that review comments generated in Requirement 5 are addressed. Requiring the BA to address and document responses to feedback generated by the RC review ensures that the reliability benefits described in Requirement 5 of an RC's cross-comparison of packages from multiple BAs are enshrined and potential wide area reliability risks avoided.

Requirement 7

Requirement 7 specifies that the near-term and the seasonal ERAs be performed.

Requirement 8

Requirement 8 specifies the energy reserve margin calculations for three different scenarios. The energy reserve margin is intended to be a clear threshold between whether the ERA's results identify acceptable or unacceptable levels of risk and require mitigation actions to be performed.

The calculation of the Energy Reserve Margin is a function of the largest single Contingency and load forecasts. The largest N-1 Contingency is a factor of the energy reserve margin to reflect to the need of having available energy beyond just meeting demand for services such as operating reserves and in case of further contingency events. A percentage of the load forecast is included as a component of the energy reserve margin to reflect the risk of load forecast error and the need to assess whether there is sufficient energy to meet that risk.

Requirement 8.1 applies to ERA cases with no contingencies. Requirement 8.2 applies to ERA cases with the largest energy contingency scenario. Requirement 8.3 applies to ERA cases with a fuel supply loss scenario as well as additional scenarios identified for consideration in seasonal ERA. Requirements 8.1 through 8.3 are progressively lower in the amount of energy that should be available because the scenarios associated with each section have different impacts from contingencies assessed. Since the contingencies directly model some of the potential energy reduction in an energy-constrained event, the energy reserve margin is reduced for those scenarios to avoid setting the threshold too high.

Requirement 9

Requirement 9 sets up the BA to apply Requirements 8.1, 8.2, and 8.3 by performing an ERA, then looking at the results of the ERA to determine what resources are available but not utilized in each iteration (e.g., hour) of the assessment, then compare the actual studied quantity to the requirements in R8. This concept is similar to Operating Reserve, but different in that all resources would be assumed to be available, ignoring temporal requirements to start generation. This is an energy requirement, not a real-time reserve requirement. If the energy reserve margins in R8 are not met, the BA is expected to implement an approved Operating Plan. The execution of the actions specified in this requirement provides the pathway to reduce the severity of energy emergencies or fully mitigate the need to implement EOP-011 Operating Plans before their triggering conditions are met in the shorter time horizon. Because ERA time horizons are significantly longer than Operating Planning Analysis required in TOP-002, ERAs provide BAs with several options which may be unavailable or unreasonable in a shorter time horizon; however, with this longer time horizon also come options that may not be concrete, such as advance notifications and opening lines of communication with regulators and other entities.

Requirements 10 & 11

Requirements 10 and 11 are more communication between the RC and BA, then between the RC and other BAs and RCs, after the ERA has been performed and it is known whether actions are required per the Operating Plan that was exchanged earlier. There are different requirements for near term ERAs than there are for seasonal ERAs. The purpose of these communications requirements is to provide situational awareness to the RC and other entities that may be impacted by energy risks in a BA. With this information, other BAs can better plan for their own reliability risk especially if they expected to rely on neighboring BAs for imports and exports. Additionally, the RC receiving this information from multiple BAs allows the RC to have a wide area view of the energy risk.

Unofficial Comment Form

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on draft one of **BAL-007-1 – Energy Reliability Assessments** by **8 p.m. Eastern, Monday, March 11, 2024.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Dominique Love (via email), or at 404-217-7578.

Background Information

Project 2022-03 currently has two assigned Standard Authorization Requests (SARs) that seek to enhance reliability by requiring entities to perform Energy Reliability Assessments (ERAs) to evaluate energy assurance and develop Corrective Action Plan(s), Operating Plan(s), or other mitigating actions to address identified risks to each respective time horizon:

- Operations/operational planning time horizon (Operations SAR)
- Planning time horizon (Planning SAR)

The proposed new Reliability Standard is based on the Operations SAR. The remaining SAR will be addressed at a later date.

The Standards Committee (SC) accepted the revised SARs at its January 25, 2023 meeting. At the same meeting, the SC authorized drafting of the Reliability Standard(s) identified in the SARs. Since that time, the team has conducted several meetings, both remote and in-person, and posted a draft of a new standard for informal comment to solicit feedback.

Summary of changes Overview

The Standard Drafting Team (SDT) proposes a new Reliability Standard BAL-007-1 and ERA Definition. The Reliability Standard BAL-007-1 outlines the process and performance for near-term and seasonal ERAs. For a detailed explanation of the requirements, please refer to the *BAL-007-1 Technical Rationale*.

In addition, the proposed definition is not balloted separately but is being balloted via the standard. As such, when voting on the standard, ballot body participants will also be voting on the proposed definition used in the standard.

Questions

1. The SDT has proposed a new Energy Reliability Assessment (ERA) definition which is intended to support the near-term and seasonal time horizons. Is the definition clear and understandable? If not, please provide the basis that supports your answer.

   ☐ Yes
   ☐ No

   Comments:

2. The SDT developed a process that defines how both near-term and seasonal ERAs will be performed and specifies the requirements for both ERAs together. Are the process and the required parameters clear and understandable? If not, please provide the basis that supports your answer or suggestions for revisions. Please specify if comments are related to the near-term ERA, seasonal ERA, or both.

   ☐ Yes
   ☐ No

   Comments:

3. The SDT proposes to require a set of scenarios to be developed which is needed in the performance of ERAs. Additionally, there is Attachment 1 that further supports the development of the set of scenarios. Are the scenarios specified in Requirement 2 the correct level or risk to consider in an ERA, and is the development of scenarios clear and understandable? If not, please provide the basis that supports your answer or suggestions for revisions. Please specify if comments are related to the near-term, seasonal ERA, or both.

   ☐ Yes
   ☐ No

   Comments:

4. The SDT proposes entities determine energy reserve margins which would provide clear criterions for whether or not the results of an ERA require Operating Plan(s) to mitigate potential energy deficiencies. Are energy reserve margins the right method to set that criterion and are the specific energy reserve margin specified in Requirement 8 the correct thresholds for both near-term and seasonal ERAs? Is this approach clear and understandable? If not, please provide the basis that supports your answer or suggestions for revision.

   ☐ Yes
   ☐ No

   Comments:

5. Does the proposed new standard address the reliability gaps or risks identified in the SAR and differentiate itself from other standard requirements? In your response, please provide any information that supports your answer.

   ☐ Yes
   ☐ No

   Comments:

6. Is the proposed standard practicable to:
   i. Be implementable?
   ii. Is the proposed standard auditable?
   iii. Able to comply with?

   In your response, please provide any information that supports your answer.

   ☐ Yes
   ☐ No

   Comments:

7. Provide any additional comments for the SDT to consider, if desired.

   Comments:

Violation Risk Factor and Violation Severity Level Justifications

Project 2022-03 Energy Assurance with Energy-Constrained Resources

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 2022-03 Energy Assurance with Energy-Constrained Resources. Each requirement is assigned a VRF and a VSL. These elements support the determination of an initial value range for the Base Penalty Amount regarding violations of requirements in FERC-approved Reliability Standards, as defined in the Electric Reliability Organizations (ERO) Sanction Guidelines. The SDT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

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

Lower Risk Requirement

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

FERC Guidelines for Violation Risk Factors

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

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

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a “binary” type requirement must be a “Severe” VSL.
Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

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

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

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

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

VRF Justifications for BAL-007-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not documenting and maintaining the process for the near-term and seasonal Energy Reliability Assessments which are required in defining the minimum standards by which near-term and seasonal Energy Reliability Assessments will be performed 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	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.

VRF Justifications for BAL-007-1, Requirement R1	
Proposed VRF	**Medium**
than One Obligation	

<table>
<tr><th colspan="4">VSLs for BAL-007-1, Requirement R1</th></tr>
<tr><th>Lower</th><th>Moderate</th><th>High</th><th>Severe</th></tr>
<tr>
<td>N/A</td>
<td>The Balancing Authority documented a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon but failed to maintain it at least annually.

OR

The Balancing Authority documented a Reliability Coordinator-reviewed Energy Reliability Assessment process for the seasonal time horizon but failed to maintain it at least annually.</td>
<td>The Balancing Authority documented and maintained a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon and seasonal time horizon but failed to include one of the required base case elements under Requirement R1 Part 1.2 or supporting rationale(s) under Requirement R1 Part 1.3 for the near-term time horizon or seasonal time horizon.</td>
<td>The Balancing Authority documented and maintained a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon and seasonal time horizon but failed to include two or more of the required base case elements under Requirement R1 Part 1.2 or supporting rationale(s) under Requirement R1 Part 1.3 for the near-term time horizon or seasonal time horizon.

OR

The Balancing Authority failed to document a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon.

OR

The Balancing Authority failed to document a Reliability Coordinator-reviewed Energy Reliability Assessment process for the seasonal time horizon.</td>
</tr>
</table>

VSL Justifications for BAL-007-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for BAL-007-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not developing, documenting, and maintaining the scenarios for the near-term and seasonal Energy Reliability Assessments which are required in defining the minimum standards by which Energy Reliability Assessments will be performed 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 BAL-007-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority developed and documented a Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon but failed to maintain them. OR The Balancing Authority developed and documented a Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the seasonal time horizon but failed to maintain them.	The Balancing Authority developed and documented Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon and seasonal time horizons but failed to include one of the scenarios of Requirement R2 Part 2.1 or supporting rationales under Requirement R2 Part 2.2 for the near-term time horizon or seasonal time horizon.	The Balancing Authority developed and documented Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon and seasonal time horizons but failed to include two or more of the scenarios of Requirement R2 Part 2.1 or supporting rationales under Requirement R2 Part 2.2 for the near-term time horizon or seasonal time horizon. OR The Balancing Authority failed to develop or document Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon. OR The Balancing Authority failed to develop or document Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the seasonal time horizon.

VSL Justifications for BAL-007-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not 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 BAL-007-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not developing, documenting and maintaining the Operating Plan(s) to mitigate unacceptable risk(s) 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 BAL-007-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to develop an Operating Plan(s) to mitigate risk identified in the Energy Reliability Assessments.

VSL Justifications for BAL-007-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R4	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that the submittal of the Energy Reliability Assessment process, the Energy Reliability Assessment scenarios, and Operating Plan(s) is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restoration 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 Low 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 Low 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 low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-007-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority submitted information that contained the Energy Reliability Assessment process, the Energy Reliability Assessment scenarios, and Operating Plan(s) but failed to submit within the mutually agreed-upon schedule.	The Balancing Authority failed to submit information that contained the Energy Reliability Assessment process, the Energy Reliability Assessment scenarios, and Operating Plan(s).

VSL Justifications for BAL-007-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment 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 BAL-007-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by each Reliability Coordinator not reviewing each submittal for coordinating the Energy Reliability Assessments with other Balancing Authorities' Energy Reliability Assessments and notifying the results of its review to each Balancing Authority 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 BAL-007-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' Energy Reliability Assessment information to avoid risks to Wide Area reliability but failed to notify each Balancing Authority within 60 calendar days.	The Reliability Coordinator failed to review each submittal for coordination with other Balancing Authorities' Energy Reliability Assessment information to avoid risks to Wide Area reliability.

VSL Justifications for BAL-007-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 BAL-007-1, Requirement R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by each Balancing Authority not addressing the reliability risks identified its Reliability Coordinator and resubmitting the updated information within 60 calendar days to ensure the most accurate information is used 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 BAL-007-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority addressed any reliability risks identified by its Reliability Coordinator and resubmitted the updated information required in Requirement R2 to its Reliability Coordinator but failed to resubmit the updated information within 60 calendar days of receipt or as specified by its Reliability Coordinator.	The Balancing Authority failed to address any reliability risks identified by its Reliability Coordinator. OR The Balancing Authority failed to resubmit the updated information required in Requirement R2 to its Reliability Coordinator.

VSL Justifications for BAL-007-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for BAL-007-1, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not performing the Energy Reliability Assessment according to the process documented in Requirement R1 using the scenarios documented in Requirement R2 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 BAL-007-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to perform Energy Reliability Assessments in accordance with its process documented in Requirement R1 using the scenarios documented in Requirement R2.

VSL Justifications for BAL-007-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R8	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that not determining the energy reserve margins for each time step of the Energy Reliability Assessment scenario which is intended to be a clear threshold between whether the Energy Reliability Assessment results identify acceptable or unacceptable levels of risk and require mitigation actions to be performed 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 BAL-007-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to determine the energy reserve margins in accordance with Requirements R8 Parts 8.1 through 8.3.

VSL Justifications for BAL-007-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R9	
Proposed VRF	**High**
NERC VRF Discussion	A VRF of High is appropriate due to the fact that a lack of implementing an Operating Plan if energy reserve margins are met could directly cause or contribute to bulk electric system 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 BAL-007-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
N/A	The	The	The Balancing Authority compared results of the Energy Reliability Assessment to the energy reserve margins in Requirement R8 but failed to implement an Operating Plan(s) developed in Requirement R3 upon determining the energy reserve margins were not met. OR The Balancing Authority failed to compare results of the Energy Reliability Assessment to the energy reserve margins in Requirement R8.

VSL Justifications for BAL-007-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R10	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that each Balancing Authority submittal of the results of the Energy Reliability Assessment to the energy reserve margins to its Reliability Coordinator is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restoration 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 Low 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 Low 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 Low VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-007-1, Requirement R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to provide the results of the Energy Reliability Assessment to its Reliability Coordinator when any of the conditions listed in Requirement R10.1 – R10.3 are met.

VSL Justifications for BAL-007-1, Requirement R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R11	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that the notification of the implementation of an Operating Plan is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restoration 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 Low 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 Low 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 Low VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-007-1, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator received results of an Energy Reliability Assessment and comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 but notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators between 24-25 hours of receiving notification.	The Reliability Coordinator received results of an Energy Reliability Assessment and comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 but notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators between 25-26 hours of receiving notification.	The Reliability Coordinator received results of an Energy Reliability Assessment and comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 but notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators between 26-27 hours of receiving notification.	The Reliability Coordinator received results of an Energy Reliability Assessment and comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 but notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators 27 hours or more of receiving notification. OR The Reliability Coordinator received results of an Energy Reliability Assessment and comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or one or more neighboring Reliability Coordinators.

VSL Justifications for BAL-007-1, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Formal Comment Period Open through March 11, 2024
Ballot Pools Forming through February 23, 2024

[Now Available]

A 45-day formal comment period for draft one of **BAL-007-1 – Energy Reliability Assessments** is open through **8 p.m. Eastern, Monday, March 11, 2024.**

Commenting

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

Reminder Regarding Corporate RBB Memberships

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

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, February 23, 2024.** Registered Ballot Body members can join the ballot pools here.

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

Next Steps

Initial ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 1 - 11, 2024**.

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

For more information or assistance, contact Standards Developer, Dominique Love (via email) or at 404-217-7578. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2022-03 Energy Assurance with Energy-Constrained Resources 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:	2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1
Comment Period Start Date:	1/25/2024
Comment Period End Date:	3/11/2024
Associated Ballots:	2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 IN 1 ST 2022-03 Energy Assurance with Energy-Constrained Resources Implementation Plan IN 1 OT

There were 57 sets of responses, including comments from approximately 186 different people from approximately 109 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT has proposed a new Energy Reliability Assessment (ERA) definition which is intended to support the near-term and seasonal time horizons. Is the definition clear and understandable? If not, please provide the basis that supports your answer.

2. The SDT developed a process that defines how both near-term and seasonal ERAs will be performed and specifies the requirements for both ERAs together. Are the process and the required parameters clear and understandable? If not, please provide the basis that supports your answer or suggestions for revisions. Please specify if comments are related to the near-term ERA, seasonal ERA, or both.

3. The SDT proposes to require a set of scenarios to be developed which is needed in the performance of ERAs. Additionally, there is Attachment 1 that further supports the development of the set of scenarios. Are the scenarios specified in Requirement 2 the correct level or risk to consider in an ERA, and is the development of scenarios clear and understandable? If not, please provide the basis that supports your answer or suggestions for revisions. Please specify if comments are related to the near-term, seasonal ERA, or both.

4. The SDT proposes entities determine energy reserve margins which would provide clear criterions for whether or not the results of an ERA require Operating Plan(s) to mitigate potential energy deficiencies. Are energy reserve margins the right method to set that criterion and are the specific energy reserve margin specified in Requirement 8 the correct thresholds for both near-term and seasonal ERAs? Is this approach clear and understandable? If not, please provide the basis that supports your answer or suggestions for revision.

5. Does the proposed new standard address the reliability gaps or risks identified in the SAR and differentiate itself from other standard requirements? In your response, please provide any information that supports your answer.

6. Is the proposed standard practicable to:
i. Be implementable?
ii. Is the proposed standard auditable?
iii. Able to comply with?
In your response, please provide any information that supports your answer.

7. Provide any additional comments for the SDT 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	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO

					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
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
Southern Company - Southern Company Services, Inc.	Colby Galloway	1,3,5,6	MRO,RF,SERC,Texas RE,WECC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Public Utility District No. 1 of Chelan County	Diane E Landry	1,3,5,6		CHPD	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC

					Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
Elizabeth Davis	Elizabeth Davis		RF,SERC	ISO/RTO Standards Review Committee	Mike Del Viscio	PJM	2	RF
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Ali Miremadi	California ISO	2	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
					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
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC

					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
					Jolly Hayden	East Texas Electric Cooperative, Inc.	NA - Not Applicable	Texas RE
					Nikki Carson-Marquis	Minnkota Power Cooperative, Inc.	1	MRO
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	SERC
LaKenya Vannorman	LaKenya Vannorman		SERC	Florida Municipal Power Agency (FMPA)	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Dan O'Hagan	Florida Municipal Power Agency	4	SERC
					Navid Nowakhtar	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					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 -	1	NPCC

						Florida Power and Light Co.		
					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
Ryan Strom	Ryan Strom		RF	Buckeye Power Group	Carl Spaetzel	Buckeye Power, Inc.	3	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Zemanek	Buckeye Power, Inc.	5	RF
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

Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
					Darian Richards	Southwest Power Pool Inc	2	MRO
					Jim William	Southwest Power Pool Inc.	2	MRO
					Mason Favazza	Southwest Power Pool Inc.	2	MRO
					Heather Harris	Southwest Power Pool Inc.	2	MRO
					Will Tootle	Southwest Power Pool Inc.	2	MRO
					Sunny Raheem	Southwest Power Pool Inc.	2	MRO
					Daniel Baker	Southwest Power Pool Inc.	2	MRO
					Margaret Quispe	Southwest Power Pool Inc.	2	MRO
					Bryan Wood	Southwest Power Pool Inc.	2	MRO
					Brian Strickland	Southwest Power Pool Inc	2	MRO
Stephen Whaite	Stephen Whaite		RF	ReliabilityFirst Ballot Body Member and Proxies	Lindsey Mannion	ReliabilityFirst	10	RF
					Stephen Whaite	ReliabilityFirst	10	RF
Western Electricity	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Phil O'Donnell	WECC	10	WECC

Coordinating Council								
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC
					Gary Dollins	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	SERC
					Heath Henry	NW Electric Power Cooperative, Inc.	3	SERC

						Tony Gott	KAMO Electric Cooperative	3	SERC
						Micah Breedlove	KAMO Electric Cooperative	1	SERC
						Brett Douglas	Northeast Missouri Electric Power Cooperative	1	SERC
						Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
						Mark Riley	Associated Electric Cooperative, Inc.	1	SERC
						Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
						Chuck Booth	Associated Electric Cooperative, Inc.	5	SERC
						Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3	SERC

1. The SDT has proposed a new Energy Reliability Assessment (ERA) definition which is intended to support the near-term and seasonal time horizons. Is the definition clear and understandable? If not, please provide the basis that supports your answer.

Richard Gilbert - Florida Reliability Coordinating Council – Member Services Division - 8 - SERC	
Answer	No
Document Name	
Comment	

The SDT defines Energy Reliability Assessment (ERA) as:

Evaluation of the resources that supply electrical energy and ancillary services for the Bulk Power System to reliably meet the expected demand during the associated time period. ERAs account for the impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).

Although FRCC generally agrees that an ERA can be defined as the "[e]*valuation of the resources that supply electrical energy and ancillary services for the Bulk Power System to reliably meet the expected demand during the associated time period*," FRCC would strike the second sentence in its entirety as being extraneous and potentially confusing.

Indeed, although accounting for the "impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources" should be implicitly understood to "reliably meet expected demand," as is already clearly stated in the first sentence of the definition, the inclusion of additional language is, at a minimum, needlessly duplicative. More troubling is that the inclusion suggests the language may be open to a different interpretation than what is explicitly stated in the first sentence, which leads to an internal ambiguity within the definition as a whole.

FRCC recommends the second sentence be stricken as follows:

Energy Reliability Assessment (ERA) *- Evaluation of the resources that supply electrical energy and ancillary services for the Bulk Power System to reliably meet the expected demand during the associated time period. [Delete: ERAs account for the impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).]*

Likes 1	Entergy, 3, Keele James
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	

WECC suggests that the DT should consider a change to support understanding: "Energy Reliability Assessment (ERA) - Evaluation of the resources (add "**ability to") (delete** "that") supply electrical energy and ancillary services for the Bulk Power System to reliably meet the expected demand during the associated time period. (delete "ERAs account for") **T**he impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel) (add "**are included in the evaluation**.")

WECC suggests inclusions (or exclusions) of items for considering the term “ancillary services” as that flexibility may allow significant inconsistencies between ERAs by a BA (as well as BAs within an Interconnection or a Reserve Sharing Group (RSG).) Voltage and frequency may be considered “ancillary services” by some entities but not by others. Set the minimum expectations and then allow variability to occur after inclusion (e.g., “ancillary services including, but are not limited to, Operating Reserves, ...)

Is the SDT making a distinction between “ancillary services" and the defined term "Ancillary Services”? Use of Glossary Terms but not reflected as defined terms (i.e. capitalized) is ambiguous and may not produce the reliability results intended.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI’s comments: EEI is of the opinion that further clarity would benefit the proposed definition of Energy Reliability Assessment. To address our concerns, we offer the following edits in boldface for consideration:

Energy Reliability Assessment (ERA): Documented evaluation of the **registered BPS** resources that supply electrical energy and ancillary services for the Bulk Power System to (*remove:* ***reliably***) meet the expected demand during (*remove:* ***the associated***) **a specified** time period. ERAs account for the impact of actions **taken to minimize the impact of energy emergencies** that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NERC Standards Review Forum (NSRF) recommends verbiage be added to describe the time component; e.g. “contemporaneously.” Also, if demand is intended to mean “the rate at which energy is being used by the customer,” the term should be capitalized since this is the existing definition for “Demand” in the NERC Glossary.

Suggested edits below: Energy Reliability Assessment (ERA) - Evaluation of the ability of resources that supply electrical energy and reserves to the Bulk Power System to reliably and contemporaneously meet the expected Demand throughout the associated evaluation period. During the 2/12/24 webinar, the SDT indicated the ERA definition is intended to apply to both the Operations and Planning horizons. If so, this definition needs to be considered with respect to how operational and/or planning models can model and/or evaluate ancillary services and fuel inventories as there may be limitations. Additionally, the MRO NSRF is seeking clarity regarding which “ancillary services” must be included in the assessment. Is the intent to assess the adequacy of Operating Reserves; i.e. spinning and supplemental for purposes of providing regulation? • If so, the MRO NSRF notes that Operating Reserves and Most Severe Single Contingency (MSSC) are already addressed under BAL-002. • Other ancillary services, e.g. frequency response and voltage support, are addressed under BAL-003 and VAR-001, with voltage and reactive control (VAR-001) being a function of the Transmission Operator. Therefore, the MRO NSRF asks the SDT clarify what BAL-007 seeks to achieve. Currently, there is a lot of overlap between proposed BAL-007 and other existing standards, including TOP-002, BAL-002 and BAL-003. [Note: TOP-002, R4, Part 4.4 already requires BAs to have an Operating Plan that addresses energy reserve requirements, including deliverability capability.] Finally, the MRO NSRF asks the final sentence be stricken to accommodate alternative approaches that do not require finite fuel inventory information. If finite fuel information is required, Generator Operators should be required to provide it to the BA.	
Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports the comments submitted by EEI.	
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	No
Document Name	

Comment	
RF recommends the SDT consider replacing “ancillary services” with Operating Reserves.	
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 supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy proposes the following ERA definition:

Energy Reliability Assessment (ERA) - Evaluation of the resources that supply electrical energy for the Bulk Power System to meet the expected demand during the assessment period, accounting for the impacts of depleted and replenished resources (e.g., fuel).

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

“See comments submitted by the Edison Electric Institute”

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

Manitoba Hydro is generally supportive of comments by the MRO NSRF. However, Manitoba Hydro sees value in retaining the term "sequential" in the definition to make it abundantly clear that respecting chronology in energy analyses is necessary to appropriately assess reliability of systems with energy limited resources such as battery storage and reservoir hydro.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	

Comment	
PNMR supports EEI's comments related to the Energy Reliability Assessment (ERA) definition and support the proposed changes in their response.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following.

The second sentence in the proposed definition appears to be a Requirement on the ERA. BC Hydro suggests that if the drafting team feels this is critical to the performance of the ERA, it should be included as a Requirement in the Standard rather than within the definition itself.

Also, unless the drafting team has opted to use the generic term demand instead of the NERC Glossary Term, the capitalized word should be used instead in the ERA definition.

BC Hydro suggests the following revised wording for the ERA Definition:

Energy Reliability Assessment (ERA) – Evaluation of the resources that supply electrical energy and necessary ancillary services for the Bulk Power System to reliably meet the expected Demand throughout the evaluation period.

Please note the addition of "necessary" in conjunction with the "ancillary services" term used in the definition. BC Hydro suggests that it should only be those ancillary services pertinent to energy reserves, such as Contingency and/or Operating Reserves.

Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA does not believe the definition is clear and understandable with respect to a Balancing Authority (BA). Much of the information needed to meet the ERA is not data currently available to a BA. BPA recommends that NERC add load serving entities and/or load responsible entities as part of the NERC Compliance Registry registration list. This way, the standard would be applicable to LSEs and/or LREs and they would be the entity responsible for compliance with this standard. BPA understands and recognizes that not all registered entities are responsible for the load within their BA footprint. BPA also recommends that another responsible entity be added to the NERC Compliance Registry registration list that would allow entities to be part of a group that would be the responsible entity for the requirements of this standard, such as is defined for BAL-002 with the Reserve Sharing Group concept. To the extent the definition requires an upstream fuel analysis, BPA respectfully suggests the BA is not the correct level for this type of assessment. BPA (as a BA) is not a fuel procurer nor a weather forecaster (for wind, water, solar, etc.). The BA is generally responsible for balancing load and generation in real-time, not forecasting either of them. While the BA could procure the forecasts from a GO or GOP (in the sense of the information seemingly required by R1.2.3), BPA believes it's more logical for a GO or GOP to own the responsibility for forecasting fuel needs and documenting environmental restrictions. In the ERA definition, the first phrase '[e]valuation of the resources…' is not an action/activity that a BA should be responsible for.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

Exelon supports the comments submitted by the EEI.

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; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the MRO NSRF comments.

Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No

Document Name	
Comment	
Ameren agrees with and supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Florida Power & Light generally supports defining the Energy Reliability Assessment (ERA) as a new NERC Glossary term, however, we do not agree with the language "impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources". It is inherent to all Balancing Authorities of the obligation to reliably meet expected demand. The second sentence in the definition adds ambiguity which could lead to misinterpretation.	
Likes 0	
Dislikes 0	
Response	
Dania Colon - Orlando Utilities Commission - 5	
Answer	No
Document Name	
Comment	
Although the FRCC generally agrees with the ERA definition, the FRCC does not agree with the inclusion of the second sentence. Accounting for the "impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources" should be implicitly understood to "reliably meet expected demand." The inclusion of the second sentence in the definition does not add clarity but instead could lead to misinterpretation. FRCC recommends deleting the entire second sentence.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute and the MRO NSRF for question #1.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 5, 3; Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye supports the comments made by ACES: We at ACES appreciate the effort put forth by the SDT to develop the new ERA definiton. While we largely agree with the currently proposed definition, we do have some minor concerns that we feel warrant further scrutiny. It is our opinion that the SDT should either capitalize all words that are currently defined in the NERC Glossary of Terms or provide alternate definitons for each term that are specific to the newly proposed Reliability Standard. Namely, both the terms “ancillary services” and “demand” are defined terms; however, neither is capitalized nor is an alternate definition provided. Therefore, it is unclear as to what these terms are referring to. Additionally, we believe that the last sentence of the proposed definiton should be removed. We believe the additional information provided by this sentence only creates additional confusion rather than reducing it.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	

SPP has a concern about the BA having the flexibility to determine the time period for the ERAs as well as what is meant by the term "ancillary services."

SPP recommends that the term "demand" be capitalized if the existing definition for "Demand" in the NERC Glossary is intended to apply; if the NERC Glossary definition is not intended to apply, SPP recommends that a different term or phrase be used that more clearly indicates the intended meaning.

Furthermore, SPP proposes the following revisions to the ERA definition (shown below).

Revised Definition

Energy Reliability Assessment (ERA) - Evaluation of the known ability of resources that supply electrical energy and reserves for the Bulk Power System to reliably meet the expected Demand during the associated time period. This evaluation should consider the impact of actions in mitigating energy reliability risks.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

SMUD and BANC support the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

Energy Reliability Assessment (ERA): Documented evaluation of the **registered BPS** resources that supply electrical energy and ancillary services for the Bulk Power System to **reliably** meet the expected demand during **the associated a specified** time period. ERAs account for the impact of actions **taken to minimize the impact of energy emergencies** that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

Further clarity to the proposed definition of Energy Reliability Assessment. To address our concerns, we offer the following edits in boldface for consideration:

Energy Reliability Assessment (ERA): Documented evaluation of the **registered BPS** resources that supply electrical energy and ancillary services for the Bulk Power System to meet the expected demand during **a specified** time period. ERAs account for the impact of actions **taken to minimize the impact of energy emergencies** that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy is of the opinion that further clarity would benefit the proposed definition of Energy Reliability Assessment. To address our concerns, we offer the following edits in boldface for consideration:

Energy Reliability Assessment (ERA): Documented evaluation of the **registered BPS** resources that supply electrical energy and ancillary services for the Bulk Power System to **reliably** meet the expected demand during **the associated a specified** time period. ERAs account for the impact of actions **taken to minimize the impact of energy emergencies** that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).

Likes 0	
Dislikes 0	
Response	

Aaron Staley - Orlando Utilities Commission - 1	
Answer	No
Document Name	
Comment	

See Tacoma Power comments.

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

Further clarity to the proposed definition of Energy Reliability Assessment is needed. To address our concerns, we offer the following edits in boldface for consideration:

Energy Reliability Assessment (ERA): Documented evaluation of the **registered BPS** resources that supply electrical energy and ancillary services for the Bulk Power System to meet the expected demand during **a specified** time period. ERAs account for the impact of actions **taken to minimize the impact of energy emergencies** that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).	
Likes 1	American Municipal Power, 5, Ritts Amy
Dislikes 0	
Response	

LaKenya Vannorman - LaKenya Vannorman On Behalf of: Chris Gowder, Florida Municipal Power Agency, 5, 6, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 6, 3; Navid Nowakhtar, Florida Municipal Power Agency, 5, 6, 3; - LaKenya Vannorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
FMPA supports and recommends implementation of Southern Company comments.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP agrees and supports comments from MRO NSRF (with SMUD/Tacoma Power). SRP also believes that the definition doesn't actually state the time frames as near-term or seasonal but uses "associated time period" and "assessment period" instead. We would like for the drafting team to clarify the definition to include relevant time frames.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	No

Document Name	
Comment	

AZPS asserts that the proposed new ERA definition is not sufficiently clear. The ERA definition lacks specificity regarding “associated time period” and suggests specifying the time period as what is written is nebulous . Additionally, it is not clear how “impact” is defined. To address our concerns, we offer the following edits in boldface and strikethrough for consideration:

Energy Reliability Assessment (ERA): **Documented e**valuation of the **registered BPS** resources that supply electrical energy and ancillary services for the Bulk Power System to meet the expected demand during **a specified** time period. ERAs account for the impact of actions **taken to minimize the impact of energy emergencies** that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).

Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	

It is unclear what is meant by “the depletion and replenishment of finite upstream resources (e.g., fuel),” as the language is very expansive and appears to require BAs to evaluate portions of the supply chain that they have no authority over and for which they cannot obtain meaningful data, such as uranium supply chains, gas pipeline design and operations, and railroad networks used for shipping coal. In addition, it is unclear whether the term “demand” is intended to have the meaning contained in the NERC Glossary or a different definition.

Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 6	
Answer	No
Document Name	
Comment	

During the 2/12/24 webinar, the SDT indicated the ERA definition is intended to apply to both the Operations and Planning horizons. If so, this definition needs to be considered with respect to how operational and/or planning models can model and/or evaluate ancillary services and fuel inventories as there may be limitations.

Additionally, more clarity is needed regarding which “ancillary services” must be included in the assessment. Is the intent to assess the adequacy of Operating Reserves; i.e. spinning and supplemental for purposes of providing regulation?

Likes 0	
Dislikes 0	

Response

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	No
Document Name	

Comment

IID proposes the following changes to the new NERC defined term:

Energy Reliability Assessment (ERA) - Evaluation of the availability of key resources that supply electrical energy and ancillary services to the Bulk Power System in order to reliably meet the expected Demand during the time period being evaluated.

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company supports the EEI comments and would add that the second sentence defines the ERA ***process***; it does not help define an ERA and should be struck.

Southern Company would suggest the following language changes:

Energy Reliability Assessment (ERA): Documented evaluation of the **registered BPS** resources that supply electrical energy and ancillary services for the Bulk Power System to meet the expected demand during **the associated and specified** time period.

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 at ACES appreciate the effort put forth by the SDT to develop the new ERA definition. While we largely agree with the currently proposed definition, we do have some minor concerns that we feel warrant further scrutiny.

It is our opinion that the SDT should either capitalize all words that are currently defined in the NERC Glossary of Terms or provide alternate definitions for each term that are specific to the newly proposed Reliability Standard. Namely, both the terms “ancillary services” and “demand” are defined terms; however, neither is capitalized nor is an alternate definition provided. Therefore, it is unclear as to what these terms are referring to.

Additionally, we believe that the last sentence of the proposed definition should be removed. We believe the additional information provided by this sentence only creates additional confusion rather than reducing it.

Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	No
Document Name	
Comment	

The ISO RTO Council Standards Review Committee (SRC) has three points we wish addressed to this question.

1) Flexible time period for ERAs.

2) Capitalization of terms if defined in the NERC Glossary.

3) Requirements for upstream fuel data.

The administrative effort needed to implement a standard must be balanced against the resulting reliability benefit. In this instance, the approach described in the standard will not work for all entities and will require some to replace existing processes that are working well with something that is less effective and more administratively burdensome.

The IRC SRC supports the BA having the flexibility to determine the time period for the ERAs.

The IRC is proposing that the ERA Definition be amended to clarify what is meant by the term “ancillary services.” The SRC also recommends that the term “demand” be capitalized if the existing definition for “Demand” in the NERC Glossary is intended to apply; if the NERC Glossary definition is not intended to apply, the SRC recommends that a different term or phrase be used that more clearly indicates the intended meaning.

The SRC also notes that a portion of the definition, as currently written, appears to solely rely on the BA in determining depletion and replenishment of finite upstream resources (e.g., fuel). BA’s that do not own, manage, or operate resources are inherently subject to limited fuel / supply chain data and information. As a result, the current language presents a compliance impediment on the BA to procure such data. The SRC proposes the following revisions to the ERA definition (below) and kindly requests the SDT to review all SRC comments holistically as we believe the revised ERA definition aligns well with our other recommendations and still meets the intended Project purpose and scope.

Energy Reliability Assessment (ERA) - Evaluation of the *known ability* of resources that supply electrical energy and *reserves* for the Bulk Power System to reliably meet the expected Demand during the associated time period. *This evaluation should consider the impact of actions in mitigating energy reliability risks.*

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Darcy O'Connell - California ISO - 2

Answer	No
Document Name	

Comment

In addition to supporting comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee, CAISO has the following comments:

- The way it is written right now, asking ERA to be completed by BA and checked by RC is bound to be marginally successful because these entities do not always have visibility to the “upstream resources” (e.g., fuel). There should be NG operators responsibility to share specific information with BAs and RC.
- Suggest using “Load forecast” instead of “expected demand”. “Load forecast” is used in OPA definition already.
- It would be beneficial to describe needed inputs of the ERA and what it is trying to achieve. “Reliably meet demand” is too broad. Prescriptive scope and scale will leave less room for guessing.
- Consider including time horizon into definition
- Phrase “the depletion and replenishment of finite upstream resource” leaves a lot interpretation on how far into the supply chain (natural gas) BAs and RCs will need to dig into. Suggest revising for better clarity on what is required
- Can the drafting team provide explanation on what does this mean: “impact of actions that occur sequentially throughout the assessment period”? Whose actions? Why “sequentially” as opposed to “concurrently”?

Likes 0	

Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	No
Document Name	
Comment	
Much of the information needed to meet the ERA is not data currently available to a BA. Chelan PUD recommends that NERC add load serving entities and/or load responsible entities as part of the NERC Functional Model. This way, the standard would be applicable to LSEs and/or LREs and they would be the entity responsible for compliance with this standard. Chelan PUD understands and recognizes that not all registered entities are responsible for the load within their BA footprint. Chelan PUD also recommends that another responsible entity be added to the NERC Functional Model that would allow entities to be part of a group that would be the responsible entity for the requirements of this standard, such as is defined for BAL-002 with the Reserve Sharing Group concept.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
NPCC RSC is seeking clarity on what is meant by ‘ancillary services’ in the ERA definition. The SDT may want to consider providing practical guidance in the Technical Rational as to the scope and scale of the fuel supply chain a BA needs to assess. The language in the current ERA definition (“the depletion and replenishment of finite upstream resources (e.g., fuel))” can seem very expansive and may appear to require BAs to evaluate portions of the supply chain for which a BA does not have the ability to obtain meaningful information. It would be helpful to include the time horizon in the definition.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
The SDT may want consider providing practical guidance in the Technical Rational as to the scope and scale of the fuel supply chain a BA needs to assess.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments: "NPCC RSC is seeking clarity on what is meant by 'ancillary services' in the ERA definition. The SDT may want to consider providing practical guidance in the Technical Rational as to the scope and scale of the fuel supply chain a BA needs to assess. The language in the current ERA definition ("the depletion and replenishment of finite upstream resources (e.g., fuel))" can seem very expansive and may appear to require BAs to evaluate portions of the supply chain for which a BA does not have the ability to obtain meaningful information."	
Likes 0	

Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	Yes
Document Name	

Comment

NPCC RSC is seeking clarity on what is meant by ‘ancillary services’ in the ERA definition.

The SDT may want to consider providing practical guidance in the Technical Rational as to the scope and scale of the fuel supply chain a BA needs to assess. The language in the current ERA definition (“the depletion and replenishment of finite upstream resources (e.g., fuel))” can seem very expansive and may appear to require BAs to evaluate portions of the supply chain for which a BA does not have the ability to obtain meaningful information.

It would be helpful to include the time horizon in the definition.

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

NPCC RSC is seeking clarity on what is meant by ‘ancillary services’ in the ERA definition.

The SDT may want to consider providing practical guidance in the Technical Rational as to the scope and scale of the fuel supply chain a BA needs to assess. The language in the current ERA definition (“the depletion and replenishment of finite upstream resources (e.g., fuel))” can seem very expansive and may appear to require BAs to evaluate portions of the supply chain for which a BA does not have the ability to obtain meaningful information.

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 Additonal Comments	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
C. A. Campbell - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Holly Mitchell - NorthWestern Energy - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. The SDT developed a process that defines how both near-term and seasonal ERAs will be performed and specifies the requirements for both ERAs together. Are the process and the required parameters clear and understandable? If not, please provide the basis that supports your answer or suggestions for revisions. Please specify if comments are related to the near-term ERA, seasonal ERA, or both.

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	
AECI would suggest splitting the operational (1-8 weeks ahead) analytics apart from the longer term (seasonal and years out). Many times these studies are performed by mulitple departments and skillsets, not a solitary department or staff member. The near term focus accounts for known load and weather forecasts whereas the longer timer horizon will be based on assumptions typical of resource planning analysis. The seasonal ERA may be a better fit in the TOP-0XX-X draft standard.	
Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	No
Document Name	
Comment	
Chelan has hydro generation and for a hydro system like Chelan PUD's, an inventory concern may not show up until late in a season. While the requirement says the process can be updated more frequently than annually, is it expected that hydro inventory concerns not known at the beginning of the year should require a process update.	
Likes 0	
Dislikes 0	
Response	
Darcy O'Connell - California ISO - 2	
Answer	No
Document Name	
Comment	

In addition to supporting comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee, CAISO has the following comments: • Propose to change to “three” days instead of “five” days, to better bridge the OPA process with ERA process. • The 150% requirement had no technical rationale behind it and could not be provided by the drafting team. Currently, BAs operate with established reserve requirement that were established by their public utilities commission and vary greatly. Propose to include analysis and establishment of this number as BA responsibility that can be communicated to the RC. What is the rationale behind 150%? • Will there be analysis done on how these requirements will affect Western Interconnection in particular? Will there be work done on regional standard for WECC? In the west, RC footprint does not match BA footprint. We have over 30 BAs in the West and only 2 US RCs. • How are disagreements in mutually agreed schedules will be arbitrated?	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
C. A. Campbell - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	
While we are in general agreement with requirement R1, we believe R1 omits a factor that may have material and consequential impacts on energy assurance analysie, especially on the near-term analysis. In the introduction to the whitepaper ”Considerations for Performing an Energy Reliability Assessment” dated March 2023, the ERATF states “[e]nergy reliability assessments are critical for assuring the reliable operation of the Bul Power System (BPS)” and “…natural gas-fired generation deliver energy to support intra-hour and intra-hour ramping to match variations in demand and energy production…” We agree with these statements and believe that that electric-gas coordination remains one of the most significant concerns of the energy transition, yet the proposed standard does little to address these specific concerns. As the recently revised reliability guideline for fuel assurance articulates states, an assessment of natural gas availability cannot be severed from how the BAs may commit and schedule natural gas-fired generators. Stated differently, natural gas generator fuel availability and operational flexibility is directly influenced by the BA’s generator commitment practices. Therefore, the BA must place the generator’s physical characteristics, its fuel supply characteristics, and the limiting conditions of the pipeline tariff in context with how the BA would expect to commit and schedule the generator in order to accurately determine whether energy is available in sufficient quantity in certain circumstances. In a recent example, a system operator’s apparent lack of awareness of how the electric and gas systems	

work together led to operating day challenges and unexpected generator outages. The operating day during tight conditions is too late to recognize the differences between the timely and intraday markets or whether fuel must be taken ratably.

While we do not dispute that natural gas supply disruptions may be a concern and should be addressed, supply disruptions are a separate and distinct problem from the scheduling concerns we are raising. As an example, the PJM footprint experienced supply disruptions during Winter Storm Elliott (WSE), and those disruptions affected a minority of pipelines serving generators. However, PJM experienced generator outages on pipelines that were not affected by supply disruptions including generators located far from the production, gathering, and processing facilities most affected. PJM's analysis of WSE demonstrates that 90% of natural gas related outages were of generators that were not

committed before the end of the gas day timely nomination cycle suggesting commitment practices may have been at least as impactful as outages caused by supply disruptions.[1]. The reasons why BAs commit generators during the operating day (as opposed to the day ahead) are beyond the scope of these comments and the reliability standards, but the consequences of singularly focusing on generator capabilities without addressing how BA practices may constrain or expand those capabilities may risk leading to faulty analyses. We encourage the SDT to add a requirement along the lines of:

"1.2.3.5 How the BA expects to commit the generator and how such commitment practices may influence the generator's ability to obtain fuel."

[1] Slide 12 of PJM's *Winter Storm Elliott Continued Outage Analysis* dated March 9, 2023 accessed at: https://www.pjm.com/-/media/committees-groups/committees/oc/2023/20230309/20230309-item-04a---winter-storm-elliott-outage-data-review.ashx

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

Comments:

The IRC SRC has three points we are seeking to be addressed to this question.

1) Flexible frequency in performing ERAs.

2) Clarification of the term Operation Plan.

3) Clarification of intent of risk reduction mitigation measures.

The SRC suggests flexibility be provided to the BA in determining the frequency at which it performs its ERAs in the operating horizon.

R1.

The SRC proposes the following clarification to R1.1: " . . .each of the following time horizons . . . ."

The SRC requests that the term “assessment period” be clarified to indicate whether it refers to the period being assessed or the period during which the assessment is being performed. The SRC also recommends that the term “likely” in R2.1.7 be replaced with the term “credible.”

R3.

The term “Operating Plans” may be misconstrued to mean actions that would be implemented in near real-time or during an emergency. Please clarify that the requirement is intended to refer to something along the lines of mitigation plans that could be implemented in advance of real-time or emergency conditions to reduce the risk in real-time. For example, ‘Operating Plan(s)’ could be replaced with **‘mitigation measure(s)**’ or ‘**risk reduction measure(s)**.’

The SRC also requests that the standard be revised to clarify whether these risk reduction measures are intended to be developed in response to the results of a particular ERA or whether a global list of potential risk reduction measures is intended to be developed before the ERA is performed (or whether BAs have the flexibility to choose either approach or use both approaches as needed in a complementary manner).

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	

Comment

Southern Company supports the EEI comments and agrees that the seasonal ERA falls outside of the functional responsibilities of the Balancing Authority and should not be included in this standard.

Likes 0	
Dislikes 0	

Response

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	No
Document Name	

Comment

IID would like to see some clarification of the role of the Reliability Coordinator (RC) in ERA process.

IID has the following questions:

- Are ERA processes, scenarios, Operating Plans, and Corrective Action Plans only reviewed by RCs for completeness or will assumptions and conclusions also be evaluated?

- If RCs are approving the ERA processes of their BAs, do they have final approval authority over the setting of "predefined criteria" established by their BAs?
- Are there going to be guidelines for the RCs to follow in evaluating the above?

Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 6	
Answer	No
Document Name	
Comment	
Due to the amount of overlap in proposed BAL-007 and other standards, it is recommended the SDT work within the existing TOP-002 framework and expand it to accommodate Energy Reliability Assessments.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
It is unclear whether the term "assessment period" in Requirement R1 refers to the period being assessed or the period during which the assessment is being performed.	
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	

With regard to R3, the Operating Plans to mitigate risks associated with ERA scenarios are overlapping with EOP-011 requirements to have Emergency Operating Plans. Does this create a “Double Jeopardy” potential for BAs? Are these meant to be developed after a potential risk is identified or before? The risks of the scenarios listed in Attachment 1 seem to align with the potential emergency conditions of EOP-011. Why not lean on EOP-011 as the criteria for the Operating Plans and to prepare for potential risks as identified by the ERA process.

Additionally, does the process need to involve the RC reviewing each BAs ERA process and scenarios? Operating Plans developed as part of R3 should be included in the EOP-011 RC review process which again potentially creates a “Double Jeopardy” condition of duplicative requirements for both the RC and the BA entities.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

For R1, AZPS suggests the Standard Drafting Team specify the assessment period, define what is considered a season, and specify the granularity of the assessments as it is not clear (e.g., hourly assessments).

AZPS agrees with the need for filling the gap between the Planning Time horizon to the Operations Planning horizon; however, it also agrees with the following EEI comments:

While the proposed requirements are clear, we have a number of concerns as currently written. First, a Seasonal ERA falls outside of the functional responsibilities for the Balancing Authority. A seasonal ERA should be a planning function and is more appropriate to be performed as a Resource Planning function. It is also outside of the stated purpose and scope of the SAR for this time horizon. We suggest that the “Seasonal ERA” be removed from this standard and incorporated into a Resource Planning standard.

Next, in requirement R1.1, the Operations Planning Time Horizon is already defined by NERC in their Time Horizons document. Additionally, “Near-term” is not a defined horizon or even a defined time period. (see https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf)

While the term “Near-term” is used inconsistently within NERC Reliability Standards and is included in the NERC Glossary (in part) as part of the term “Near-Term Transmission Planning Horizon,” its use in Requirement R1 is confusing. To address this concern, the SDT should align this standard to those defined time periods already defined by NERC. For example, the SDT could replace “Near-term” in BAL-007-1 with the NERC defined term of “Peak Demand” period. Noting that the NERC glossary of terms defines “Peak Demand” is defined as, “The highest hourly integrated Net Energy for Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year).”

With this in mind, a Peak Demand time period could be next-day to up to one month out from Real-time. This time period definition would place borders around the study dates that would be allowed within an ERA, however, this Peak Demand period would not tie the BA to a duration to perform ERAs. For lack of a better name this Peak Demand time period could be called “monthly Peak Demand period.”

EEI additionally finds the frequency and duration requirement language for Near-Term ERAs to be confusing in its attempt to provide flexibility. We maintain that the Balancing Authority should determine the frequency, duration, and granularity of the ERAs based on area, region, or market needs.

To address these concerns, we propose the following changes to R1 (in boldface):

R1. Each Balancing Authority shall document and maintain a Reliability Coordinator-reviewed Energy Reliability Assessment (ERA) process, which shall be reviewed **and updated as necessary every 24 months**. The ERA process document shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. Identify the frequency and duration of the ERAs with a corresponding rationale:

1.1.1. **The study dates for which an ERA may be performed encompass a monthly Peak Demand period defined at between day-ahead to no more than one month out from Real-time.**

1.1.2 **The ERA shall be performed during this time period at a frequency, duration, granularity, AND with a beginning study date as determined by the Balancing Authority to sufficiently assess the risk of energy emergencies.**

We are also concerned that within Requirement R1.2, there are terms that are unclear. Referring to the ERA starting conditions of the ERA {C}[A1]{C} {C}[A2]{C} as "base cases" infers base case model development for power flow models, which is not the intent of the requirement. To address this issue consider changing "base cases" to "expected conditions" under which the ERA would be performed.

Next, "Time series demand" is neither a NERC defined term, nor is it defined in the standard and needs to be clarified as to its intent. While we believe the term is intended to include the expected demand over each time-step of the study duration, we suggest the SDT consider using more descriptive language to codify the meaning.

To address our concerns, we suggest the proposed changes to Requirement R1.2 (in bold face below):

1.2 Include a process for the development of the base case **expected conditions** that includes but is not limited to the following up-to-date data:

1.2.1. **Expected demand over each time-step of the study duration.**

1.2.2. Demand response, as appropriate;

1.2.3. Generator capability considering known constraints of:

1.2.3.1. Availability, including planned outages, and flexibility;

1.2.3.2. Fuel supply and inventory concerns;

1.2.3.3. Fuel switching capabilities; and

1.2.3.4. Environmental constraints.

1.2.4. Energy transfer assumptions; and

1.2.5. Energy storage capability.

1.3. Include a documented rationale for the base case elements chosen in Requirement R1.2.

Finally, a review time of 24 months for the ERA Process would be a more practical period as it would allow more time to review performance throughout the year and allow the Balancing Authority to work through any needed changes.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	No
Document Name	
Comment	
SRP agrees and supports comments from Tacoma Power. In addition, SRP is unclear on what the short-term time frame is because it's as short as five days and as long as 6 weeks. In addition, it is also unclear how often an ERA is needed to be performed given the lack of specificity in time frames. Is NERC expecting an ERA once per month? What is the expectation for seasonal ERAs?	
Likes 0	
Dislikes 0	
Response	

LaKenya Vannorman - LaKenya Vannorman On Behalf of: Chris Gowder, Florida Municipal Power Agency, 5, 6, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 6, 3; Navid Nowakhtar, Florida Municipal Power Agency, 5, 6, 3; - LaKenya Vannorman, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
FMPA supports and recommends implementation of Southern Company comments.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

There are a number of concerns as currently written. First, a Seasonal ERA falls outside of the functional responsibilities for the Balancing Authority. A seasonal ERA should be a planning function and is more appropriate to be performed as a Resource Planning function. It is also outside of the stated purpose and scope of the SAR for this time horizon. We suggest that the "Seasonal ERA" be removed from this standard and incorporated into a Resource Planning standard.

Next, in requirement R1.1, the Operations Planning Time Horizon is already defined by NERC in their Time Horizons document. Additionally, "Near-term" is not a defined horizon or even a defined time period. (see https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf)

While the term “Near-term” is used inconsistently within NERC Reliability Standards and is included in the NERC Glossary (in part) as part of the term “Near-Term Transmission Planning Horizon”, its use in Requirement R1 is confusing. To address this concern, the SDT should align this standard to those defined time periods already defined by NERC. For example, the SDT could replace “Near-term” in BAL-007-1 with the NERC defined term of “Peak Demand” period. Noting that the NERC glossary of terms defines “Peak Demand” is defined as, “The highest hourly integrated Net Energy for Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year).”

With this in mind, a Peak Demand time period could be next day to up to one month out from Real-time. This time period definition would place borders around the study dates that would be allowed within an ERA, however, this Peak Demand period would not tie the BA to a duration to perform ERAs. For lack of a better name this Peak Demand time period could be called “monthly Peak Demand period.”

The frequency and duration requirement language for Near-Term ERAs to be confusing in its attempt to provide flexibility. We maintain that the Balancing Authority should determine the frequency, duration, and granularity of the ERAs based on area, region, or market needs.

To address these concerns, we propose the following changes to R1 (in boldface):

R1. Each Balancing Authority shall document and maintain a Reliability Coordinator-reviewed Energy Reliability Assessment (ERA) process, which shall be reviewed **and updated as necessary every 24 months**. The ERA process document shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. Identify the frequency and duration of the ERAs with a corresponding rationale:

1.1.1. **The study dates for which an ERA may be performed encompass a monthly Peak Demand period defined at between day-ahead to no more than one month out from Real-time.**

1.1.2 **The ERA shall be performed during this time period at a frequency, duration, granularity, AND with a beginning study date as determined by the Balancing Authority to sufficiently assess the risk of energy emergencies.**

There are terms that are unclear within Requirement R1.2. Referring to the ERA starting conditions of the ERA as “base cases” infers base case model development for power flow models, which is not the intent of the requirement. To address this issue consider changing “base cases” to “expected conditions” under which the ERA would be performed.

Next, “Time series demand” is neither a NERC defined term, nor is it defined in the standard and needs to be clarified as to its intent. While we believe the term is intended to include the expected demand over each time-step of the study duration, we suggest the SDT consider using more descriptive language to codify the meaning.

To address our concerns, we suggest the proposed changes to Requirement R1.2 (in bold face below):

1.2 Include a process for the development of the **expected conditions** that includes but is not limited to the following up-to-date data:

1.2.1. **Expected demand over each time-step of the study duration.**

1.2.2. Demand response, as appropriate;

1.2.3. Generator capability considering known constraints of:

1.2.3.1. Availability, including planned outages, and flexibility;

1.2.3.2. Fuel supply and inventory concerns;

1.2.3.3. Fuel switching capabilities; and

1.2.3.4. Environmental constraints.

1.2.4. Energy transfer assumptions; and

1.2.5. Energy storage capability.

1.3. Include a documented rationale for the elements chosen in Requirement R1.2.

Finally, a review time of 24 months for the ERA Process would be a more practical period as it would allow more time to review performance throughout the year and allow the Balancing Authority to work through any needed changes.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1

Answer	No
Document Name	

Comment

See Tacoma Power comments.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

While the proposed requirements are clear, we have a number of concerns as currently written. First, a Seasonal ERA falls outside of the functional responsibilities for the Balancing Authority. A seasonal ERA should be a planning function and is more appropriate to be performed as a Resource Planning function. It is also outside of the stated purpose and scope of the SAR for this time horizon. We suggest that the "Seasonal ERA" be removed from this standard and incorporated into a Resource Planning standard.

Next, in requirement R1.1, the Operations Planning Time Horizon is already defined by NERC in their Time Horizons document. Additionally, "Near-term" is not a defined horizon or even a defined time period. (see https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf)

While the term "Near-term" is used inconsistently within NERC Reliability Standards and is included in the NERC Glossary (in part) as part of the term "Near-Term Transmission Planning Horizon", its use in Requirement R1 is confusing. To address this concern, the SDT should align this standard to those defined time periods already defined by NERC. For example, the SDT could replace "Near-term" in BAL-007-1 with the NERC defined term of "Peak Demand" period. Noting that the NERC glossary of terms defines "Peak Demand" is defined as, "The highest hourly integrated Net Energy for Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year)."

With this in mind, a Peak Demand time period could be next-day to up to one month out from Real-time. This time period definition would place borders around the study dates that would be allowed within an ERA, however, this Peak Demand period would not tie the BA to a duration to perform ERAs. For lack of a better name this Peak Demand time period could be called "monthly Peak Demand period."

NV Energy additionally finds the frequency and duration requirement language for Near-Term ERAs to be confusing in its attempt to provide flexibility. We maintain that the Balancing Authority should determine the frequency, duration, and granularity of the ERAs based on area, region, or market needs.

To address these concerns, we propose the following changes to R1 (in boldface):

R1. Each Balancing Authority shall document and maintain a Reliability Coordinator-reviewed Energy Reliability Assessment (ERA) process, which shall be reviewed **at least annually and updated, if necessary and updated as necessary every 24 months**. The ERA process document shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. Identify the frequency and duration of the ERAs with a corresponding rationale **for each following time horizons**:

1.1.1. Near-term; and **The study dates for which an ERA may be performed encompass a monthly Peak Demand period defined at between day-ahead to no more than one month out from Real-time.**

1.1.1.1. The end of the near-term assessment period shall be greater than five days and less than six weeks from the start of the assessment.

1.1.1.2 Each subsequent near-term assessment period shall partially overlap the previous near-term assessment period.

1.1.2 **Seasonal; The ERA shall be performed during this time period at a frequency, duration, granularity, AND with a beginning study date as determined by the Balancing Authority to sufficiently assess the risk of energy emergencies.**

1.1.2.1 Seasonal ERAs shall be performed for a minimum of two seasons that cover a calendar year that is representative of seasonal risks for operations.

1.1.2.2 Document a deadline for completing each seasonal ERA based on mitigation options for each seasonal ERA.

We are also concerned that within Requirement R1.2, there are terms that are unclear. Referring to the ERA starting conditions of the ERA as "base cases" infers base case model development for power flow models, which is not the intent of the requirement. To address this issue consider changing "base cases" to "expected conditions" under which the ERA would be performed.

Next, "Time series demand" is neither a NERC defined term, nor is it defined in the standard and needs to be clarified as to its intent. While we believe the term is intended to include the expected demand over each time-step of the study duration, we suggest the SDT consider using more descriptive language to codify the meaning.

To address our concerns, we suggest the proposed changes to Requirement R1.2 (in bold face below):

1.2 Include a process for the development of the base case **expected conditions** that includes but is not limited to the following up-to-date data:

1.2.1. **Time series demand; Expected demand over each time-step of the study duration.**

1.2.2. Demand response, as appropriate;

1.2.3. Generator capability considering known constraints of:

1.2.3.1. Availability, including planned outages, and flexibility;

1.2.3.2. Fuel supply and inventory concerns;

1.2.3.3. Fuel switching capabilities; and

1.2.3.4. Environmental constraints.

1.2.4. **Documented** Energy transfer assumptions; and

1.2.5. Energy storage capability.

1.3. Include a documented rationale for the base case elements chosen in Requirement R1.2.

Finally, a review time of 24 months for the ERA Process would be a more practical period as it would allow more time to review performance throughout the year and allow the Balancing Authority to work through any needed changes.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

There are a number of concerns as currently written. First, a Seasonal ERA falls outside of the functional responsibilities for the Balancing Authority. A seasonal ERA should be a planning function and is more appropriate to be performed as a Resource Planning function. It is also outside of the stated purpose and scope of the SAR for this time horizon. We suggest that the “Seasonal ERA” be removed from this standard and incorporated into a Resource Planning standard.

Next, in requirement R1.1, the Operations Planning Time Horizon is already defined by NERC in their Time Horizons document. Additionally, “Near-term” is not a defined horizon or even a defined time period. (see https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf)

While the term “Near-term” is used inconsistently within NERC Reliability Standards and is included in the NERC Glossary (in part) as part of the term “Near-Term Transmission Planning Horizon”, its use in Requirement R1 is confusing. To address this concern, the SDT should align this standard to those defined time periods already defined by NERC. For example, the SDT could replace “Near-term” in BAL-007-1 with the NERC defined term of “Peak Demand” period. Noting that the NERC glossary of terms defines “Peak Demand” is defined as, “The highest hourly integrated Net Energy for Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year).”

With this in mind, a Peak Demand time period could be next-day to up to one month out from Real-time. This time period definition would place borders around the study dates that would be allowed within an ERA, however, this Peak Demand period would not tie the BA to a duration to perform ERAs. For lack of a better name this Peak Demand time period could be called “monthly Peak Demand period.”

The frequency and duration requirement language for Near-Term ERAs to be confusing in its attempt to provide flexibility. We maintain that the Balancing Authority should determine the frequency, duration, and granularity of the ERAs based on area, region, or market needs.

To address these concerns, we propose the following changes to R1 (in boldface):

R1. Each Balancing Authority shall document and maintain a Reliability Coordinator-reviewed Energy Reliability Assessment (ERA) process, which shall be reviewed **and updated as necessary every 24 months**. The ERA process document shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. Identify the frequency and duration of the ERAs with a corresponding rationale

1.1.1. **The study dates for which an ERA may be performed encompass a monthly Peak Demand period defined at between day-ahead to no more than one month out from Real-time.**

1.1.2 **The ERA shall be performed during this time period at a frequency, duration, granularity, AND with a beginning study date as determined by the Balancing Authority to sufficiently assess the risk of energy emergencies.**

There are terms that are unclear within Requirement R1.2. Referring to the ERA starting conditions of the ERA as “base cases” infers base case model development for power flow models, which is not the intent of the requirement. To address this issue consider changing “base cases” to “expected conditions” under which the ERA would be performed.

Next, “Time series demand” is neither a NERC defined term, nor is it defined in the standard and needs to be clarified as to its intent. While we believe the term is intended to include the expected demand over each time-step of the study duration, we suggest the SDT consider using more descriptive language to codify the meaning.

To address our concerns, we suggest the proposed changes to Requirement R1.2 (in bold face below):

1.2 Include a process for the development of the base case **expected conditions** that includes but is not limited to the following up-to-date data:

1.2.1.

1.2.2. Demand response, as appropriate;

1.2.3. Generator capability considering known constraints of:

1.2.3.1. Availability, including planned outages, and flexibility;

1.2.3.2. Fuel supply and inventory concerns;

1.2.3.3. Fuel switching capabilities; and

1.2.3.4. Environmental constraints.

1.2.4. Energy transfer assumptions; and

1.2.5. Energy storage capability.

1.3. Include a documented rationale for the base case elements chosen in Requirement R1.2.

Finally, a review time of 24 months for the ERA Process would be a more practical period as it would allow more time to review performance throughout the year and allow the Balancing Authority to work through any needed changes.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

There are a number of concerns as currently written. First, a Seasonal ERA falls outside of the functional responsibilities for the Balancing Authority. A seasonal ERA should be a planning function and is more appropriate to be performed as a Resource Planning function. It is also outside of the stated purpose and scope of the SAR for this time horizon. We suggest that the "Seasonal ERA" be removed from this standard and incorporated into a Resource Planning standard.

Next, in requirement R1.1, the Operations Planning Time Horizon is already defined by NERC in their Time Horizons document. Additionally, "Near-term" is not a defined horizon or even a defined time period. (see https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf)

While the term "Near-term" is used inconsistently within NERC Reliability Standards and is included in the NERC Glossary (in part) as part of the term "Near-Term Transmission Planning Horizon", its use in Requirement R1 is confusing. To address this concern, the

SDT should align this standard to those defined time periods already defined by NERC. For example, the SDT could replace "Near-term" in BAL-007-1 with the NERC defined term of "Peak Demand" period. Noting that the NERC glossary of terms defines "Peak Demand" is defined as, "The highest hourly integrated Net Energy for Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year)."

With this in mind, a Peak Demand time period could be next-day to up to one month out from Real-time. This time period definition would place borders around the study dates that would be allowed within an ERA, however, this Peak Demand period would not tie the BA to a duration to perform ERAs. For lack of a better name this Peak Demand time period could be called "monthly Peak Demand period."

The frequency and duration requirement language for Near-Term ERAs to be confusing in its attempt to provide flexibility. We maintain that the Balancing Authority should determine the frequency, duration, and granularity of the ERAs based on area, region, or market needs.

To address these concerns, we propose the following changes to R1 (in boldface):

R1. Each Balancing Authority shall document and maintain a Reliability Coordinator-reviewed Energy Reliability Assessment (ERA) process, which shall be reviewed **at least annually and updated, if necessary and updated as necessary every 24 months**. The ERA process document shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. Identify the frequency and duration of the ERAs with a corresponding rationale **for each following time horizons**:

1.1.1. Near-term; and **The study dates for which an ERA may be performed encompass a monthly Peak Demand period defined at between day-ahead to no more than one month out from Real-time.**

1.1.1.1. The end of the near-term assessment period shall be greater than five days and less than six weeks from the start of the assessment.

1.1.1.2 Each subsequent near-term assessment period shall partially overlap the previous near-term assessment period.

1.1.2 **Seasonal; The ERA shall be performed during this time period at a frequency, duration, granularity, AND with a beginning study date as determined by the Balancing Authority to sufficiently assess the risk of energy emergencies.**

1.1.2.1 Seasonal ERAs shall be performed for a minimum of two seasons that cover a calendar year that is representative of seasonal risks for operations.

1.1.2.2 Document a deadline for completing each seasonal ERA based on mitigation options for each seasonal ERA.

There are terms that are unclear within Requirement R1.2. Referring to the ERA starting conditions of the ERA as "base cases" infers base case model development for power flow models, which is not the intent of the requirement. To address this issue consider changing "base cases" to "expected conditions" under which the ERA would be performed.

Next, "Time series demand" is neither a NERC defined term, nor is it defined in the standard and needs to be clarified as to its intent. While we believe the term is intended to include the expected demand over each time-step of the study duration, we suggest the SDT consider using more descriptive language to codify the meaning.

To address our concerns, we suggest the proposed changes to Requirement R1.2 (in bold face below):

1.2 Include a process for the development of the base case **expected conditions** that includes but is not limited to the following up-to-date data:

1.2.1. **Time series demand; Expected demand over each time-step of the study duration.**

1.2.2. Demand response, as appropriate;

1.2.3. Generator capability considering known constraints of:

1.2.3.1. Availability, including planned outages, and flexibility;

1.2.3.2. Fuel supply and inventory concerns;

1.2.3.3. Fuel switching capabilities; and

1.2.3.4. Environmental constraints.

1.2.4. **Documented** Energy transfer assumptions; and

1.2.5. Energy storage capability.

1.3. Include a documented rationale for the base case elements chosen in Requirement R1.2.

Finally, a review time of 24 months for the ERA Process would be a more practical period as it would allow more time to review performance throughout the year and allow the Balancing Authority to work through any needed changes.

Likes 0	

Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

SMUD and BANC support the comments submitted by Tacoma Power.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has a concern that the proposed standard might conflict with other standards (TOP-002, EOP-011). It's our understanding that the assessment has the potential to overlap or create conflict.

We recommend that the drafting team coordinates with the TOP and EOP drafting teams to ensure that all requirements align to reduce conflict as well as address the appropriate time intervals that are not covered in those standards.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) to question #2. Evergy also encourages the drafting team to review the comments regarding administrative effort versus reliability benefit in the MRO NSRF's response to question #2 which Evergy also support and incorporate by reference.

Likes 0	
Dislikes 0	

Response

Dania Colon - Orlando Utilities Commission - 5

Answer	No
Document Name	

Comment

The process and the required parameters are not clear and understandable. FRCC has a concern that this requirement is written to only address BAs and does not allow for studies to be performed at a Reserve Sharing Group level instead of individual BAs. The FRCC RC has a Reserve Sharing Group with nine BAs. With the current language, the BAs and RC would be responsible for reviewing nine BAs near-term and seasonal time horizons scenarios and document those reviews along with the administrative burden of compiling evidence for all of those reviews (R4). In addittion, the creation of compliance evidence for the implementation of the ongoing near-term ERAs will be cumbersome due to the large number of studies and their documented scenarios, rationale, and criteria.
The FRCC already performs coordinated next-day, 8-day, 28-day, and four seasonal studies for the entire FRCC RC area without the requirement of compiling burdensome evidence noted by the new standard requirements. If each of the nine BAs in the FRCC RC area were required to independently perform the near-term and seasonal ERAs as described in this standard, it would be a constant influx and overabundance of study results for the RC to review without improving the situational awareness that we currently achieve through our coordinated next-day, 8-day, 28-day, and seasonal assessments.
The near-term language used in this requirement is not a NERC defined time horizon. The NERC Time Horizons document outlines the appropriate time horizons to be utilized for each requirement (see excerpt below).
“When establishing a time horizon for each requirement, the following criteria should be used:

1. Long-term Planning – a planning horizon of one year or longer.
2. Operations Planning – operating and resource plans from day-ahead, up to, and including seasonal.
3. Same-day Operations – routine actions required within the timeframe of a day, but not real-time.
4. Real- time Operations – actions required within one hour or less to preserve the reliability of the bulk electric system.
5. Operations Assessment – follow-up evaluations and reporting of real-time operations.”

The timing requirements outlined for the near-term language are confusing and difficult to apply to a calendar-based approach. For example, “the end of the near-term assessment period shall be greater than five days and less than six weeks from the start of the assessment” is confusing. FRCC recommends a simpler approach to the requirement like, 28-day assessment for daily peak demand.
In addition, FRCC believes the intent is for these studies to include any known transmission or generation outages in the study scenarios. It would be clearer to state that in the scenario concepts.

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Florida Power & Light does not agree that the required parameters are clear and understandable. A Seasonal ERA as defined by the SDT is within the responsibility of the Resource Planner; not the Balancing Authority. It is also outside of the stated purpose and scope of the SAR for this time horizon. The "Seasonal ERA" is also the responsibility of the Resource Planner to analyze "Seasonal Load variation". Additionally, in the term "Near-term" is used inconsistently within NERC standards and including another time frame called "Near-term" can cause confusion and any proposed subset time periods of the NERC defined horizon should also be tied to existing NERC defined time periods for clarity.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports MISO's 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; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	

Tacoma Power supports the SDT's approach to either creating a new BAL Standard like BAL-007 or revising an existing BAL Standard (i.e., BAL-002). Tacoma Power does not support adding Balancing Authority responsibilities to the TOP Standards, even though TOP-002-5 R8 will include similar seasonal assessments.

However, additional changes are needed to BAL-007 to make the process and the required parameters more clear and understandable. The NERC standards should be results-based, focusing on the outcome to be achieved. A results-based focus would accommodate alternative methods for assessing energy reliability that are equally as good as the approach currently described under BAL-007, while allowing entities who would like to use the method outlined under BAL-007 the ability to do so as well. As written, BAL-007 limits "how" an entity may perform the ERA evaluation.

To rectify this, Tacoma Power recommends revising the standard to focus on the objective, i.e. ensuring energy sufficiency, by requiring the completion of the three (3) basic activities outlined in the Technical Rationale (page 2).

- Developing and documenting ERA process, scenario, and Operating Plans
- Performing ERAs and comparing to an Energy Reserve Margin that allows for regional flexibility; and
- If Energy Reserve Margins are not met, implementing Operating Plan to mitigate energy reliability risks

Ultimately, the BA should have some discretion in determining when to develop a formal written Operating Plan(s) within its ERA process as, the further out an Operating Plan is written, the more times it will need to be modified. The proposed new Requirements should not require specific mitigating actions, such as a fixed amount of generating resources on standby. In addition, the value of advance planning may vary by system. Next day planning may be sufficient for systems with a smaller risk profile while systems with higher risk profile may benefit from additional advance planning. Tacoma Power looks forward to engaging with the SDT during future interactions to help draft language that allows for multiple ERA evaluation approaches, while still providing objective and results-based measures.

Likes 3	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia; Orlando Utilities Commission, 1, Staley Aaron; American Municipal Power, 5, Ritts Amy
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
BPA recommends the SDT revise R1. The specifics called for in R1.2.3 seem like good things. However, for a hydro system like BPA's, an inventory concern may not show up until late in a season. While the requirement says the process can be updated more frequently than annually, is it expected that hydro inventory concerns not known at the beginning of the year should require a process update, replete with review/approval by the RC? BPA does not understand the intent behind the R1.2.4 requirement and seeks clarity from the SDT. Additionally, BPA is unclear as to the detail needed in the base case/studies that would sufficiently distinguish it from a transfer limit study done by the TO or TOP.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
The Standard appears to be drafted as a methodology and is very prescriptive on how to achieve the identified objectives stated in the Purpose section of the Standard, i.e. mitigate risks of energy emergencies due to resource mix and fuel availability. BC Hydro suggests that the Standard only mandate that the entities develop an ERA process and/or procedure, perform ERAs accordingly, and implement corrective actions if energy deficiencies are identified. Existing Standards EOP-011 and TOP-002 offer a robust platform to build on and avoid duplicative requirements.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR supports EEI's recommended changes to R1 and the frequency change from 1 year to 24 months for ERA process review and reassignment of responsibility for the Seasonal ERA studies from the Balancing Authority to the Resource Planner.	
Likes 0	
Dislikes 0	

Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Manitoba Hydro agrees with comments provided by the MRO NSRF and the recommendation to have the focus be results-based. This will enable BAs who are most familiar the unique aspects of their respective systems best design, schedule and perform ERAs.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports and recommends implementation of EEI provided comments. Additionally, the process should require the BA to define normal load and high load assumptions for both the near-term and seasonal ERAs. In some instances of a near-term ERA, the 'high load' assumption may not be much different to the 'normal load' assumption, given other forecast related information. Having the BA define such parameters in the RC-reviewed process will allow the RC to weigh-in on such assumptions.	
Likes 0	
Dislikes 0	

Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
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 supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Any requirements regarding frequency of assessments should be based on the specific facts and circumstances of the region. Depending on the region and season, having an affirmative requirement in all months or for all weeks (i.e., in the near-term assessment) may not be necessary. Further, the requirement for overlapping assessment periods for the near-term ERAs may be unnecessary in all seasons and may only be helpful in higher-risk or higher-load seasons. Additionally, the ERA process in general appears duplicative of other planning processes that utilities routinely undertake, including Integrated Resource Planning, Seasonal Readiness planning, risk management, resource adequacy planning, and month-ahead and day-ahead planning. It is unclear how this process is intended to differ from those, nor is it clear what benefit it would provide above and beyond those existing processes.	
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	No
Document Name	
Comment	
RF recommends wind, solar, and hydro/rain forecasts be included as an explicit category under R1 Part 1.2.3.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Recognizing the challenge of drafting a standard from scratch, the MRO NSRF sincerely appreciates the effort dedicated to crafting BAL-007. That said, the MRO NSRF has several concerns regarding BAL-007 and offers the following recommendations. 1. BAL-007 should be results-based, focusing on the outcome to be achieved. A results-based focus would accommodate a variety of methods for assessing energy reliability that are equally as valid as the approach outlined under BAL-007. The standard should accommodate the approach	

currently outlined under BAL-007 and the flexibility for BAs to employ alternate approaches now and into the future without having to revise the standard.

The MRO NSRF notes this could be accomplished by requiring the three (3) activities outlined in the Technical Rationale (page 2).

• Developing and documenting ERA process, scenario, and Operating Plans

• Performing ERAs and comparing to Energy Reserve Margin; and

• If Energy Reserve Margins are not met, implementing an Operating Plan to mitigate energy reliability risks

2. Expand existing TOP-002 versus drafting a new standard (e.g. BAL-007). For example (using existing TOP-002, R4 as a model):

RX. Each Balancing Authority shall have a multi-day, forward looking Energy Reliability Assessment (ERA) that leads into its next day Operating Plan cited in Requirement R4 that addresses: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1 Expected generation resource availability, commitment and dispatch

4.2 Expected energy transfers

4.3 Demand patterns

4.4 Capacity and energy reserve requirements, including deliverability capability

4.5 Relevant risk scenarios

4.6 Coordination with neighboring BAs

Working within the existing TOP-002 framework will eliminate the need to repeat existing requirements: R4 (entity notification) and R5 (providing a copy to the RC).

Thought and consideration should be given to administrative effort versus reliability benefit as the benefit associated with ERAs may vary by system. The Balancing Authority should have some discretion as to when an Operating Plan(s) is issued prior to next day as, the further out

an Operating Plan is written, the more times it will need to be modified. Existing TOP-002, requirement R5, provides a backstop for Operating Plans once an entity reaches next day.

Finally, language in the **FERC-NERC Winter Storm Elliott Report**, **Recommendation #8** could be another source from which to draw ideas as illustrated below:

Balancing Authorities should assess whether … a multi-day risk assessment processes or advance or multi-day reliability commitments—are needed to address anticipated energy shortages or transmission system-related reliability problems… by performing energy risk assessments... BAs should consider the following:

A. how to account for uncertainty in load forecasts, generating unit fuel availability and extreme weather availability, and the effects of extreme weather across multiple regions; and

B. committing generating units prior to the onset of extreme weather

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI's comments: While the proposed requirements are clear, we have a number of concerns as currently written. First, a Seasonal ERA falls outside of the functional responsibilities for the Balancing Authority. A seasonal ERA should be a planning function and is more appropriate to be performed as a Resource Planning function. It is also outside of the stated purpose and scope of the SAR for this time horizon. We suggest that the "Seasonal ERA" be removed from this standard and incorporated into a Resource Planning standard.

Next, in requirement R1.1, the Operations Planning Time Horizon is already defined by NERC in their Time Horizons document. Additionally, "Near-term" is not a defined horizon or even a defined time period. (see https://www.nerc.com/pa/Stand/Resources/Documents/Time_Horizons.pdf)

While the term "Near-term" is used inconsistently within NERC Reliability Standards and is included in the NERC Glossary (in part) as part of the term "Near-Term Transmission Planning Horizon", its use in Requirement R1 is confusing. To address this concern, the SDT should align this standard to those defined time periods already defined by NERC. For example, the SDT could replace "Near-term" in BAL-007-1 with the NERC defined term of "Peak Demand" period. Noting that the NERC glossary of terms defines "Peak Demand" is defined as, "The highest hourly integrated Net Energy for Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year)."

With this in mind, a Peak Demand time period could be next-day to up to one month out from Real-time. This time period definition would place borders around the study dates that would be allowed within an ERA, however, this Peak Demand period would not tie the BA to a duration to perform ERAs. For lack of a better name this Peak Demand time period could be called "monthly Peak Demand period."

EEI additionally finds the frequency and duration requirement language for Near-Term ERAs to be confusing in its attempt to provide flexibility. We maintain that the Balancing Authority should determine the frequency, duration, and granularity of the ERAs based on area, region, or market needs.

To address these concerns, we propose the following changes to R1 (in boldface):

R1. Each Balancing Authority shall document and maintain a Reliability Coordinator-reviewed Energy Reliability Assessment (ERA) process, which shall be reviewed (*remove:* ***at least annually and updated, if necessary***) **and updated as necessary every 24 months**. The ERA process document shall: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. Identify the frequency and duration of the ERAs with a corresponding rationale (*remove:* ***for each following time horizons***):

1.1.1. (*Remove: Near-term; and*) **The study dates for which an ERA may be performed encompass a monthly Peak Demand period defined at between day-ahead to no more than one month out from Real-time.**

(*remove*: ***1.1.1.1. The end of the near-term assessment period shall be greater than five days and less than six weeks from the start of the assessment.)***

(*remove:* 1.1.1.2 *Each subsequent near-term assessment period shall partially overlap the previous near-term assessment period.)*

1.1.2 (*remove:* ***Seasonal;))*** **The ERA shall be performed during this time period at a frequency, duration, granularity, AND with a beginning study date as determined by the Balancing Authority to sufficiently assess the risk of energy emergencies.**

(*remove:* **1.1.2.1 Seasonal ERAs shall be performed for a minimum of two seasons that cover a calendar year that is representative of seasonal risks for operations.)**

(*remove:* 1.1.2.2 Document a deadline for completing each seasonal ERA based on mitigation options for each seasonal ERA.)

We are also concerned that within Requirement R1.2, there are terms that are unclear. Referring to the ERA starting conditions of the ERA as "base cases" infers base case model development for power flow models, which is not the intent of the requirement. To address this issue consider changing "base cases" to "expected conditions" under which the ERA would be performed.

Next, "Time series demand" is neither a NERC defined term, nor is it defined in the standard and needs to be clarified as to its intent. While we believe the term is intended to include the expected demand over each time-step of the study duration, we suggest the SDT consider using more descriptive language to codify the meaning.

To address our concerns, we suggest the proposed changes to Requirement R1.2 (in bold face below):

1.2 Include a process for the development of the (*remove: base case*) **expected conditions** that includes but is not limited to the following up-to-date data:

1.2.1. **(***remove:* ***Time series demand*****); Expected demand over each time-step of the study duration.**

1.2.2. Demand response, as appropriate;

1.2.3. Generator capability considering known constraints of:

1.2.3.1. Availability, including planned outages, and flexibility;

1.2.3.2. Fuel supply and inventory concerns;

1.2.3.3. Fuel switching capabilities; and

1.2.3.4. Environmental constraints.

1.2.4. (*remove:* ***Documented***) Energy transfer assumptions; and

1.2.5. Energy storage capability.

1.3. Include a documented rationale for the (remove: base case) elements chosen in Requirement R1.2.

Finally, a review time of 24 months for the ERA Process would be a more practical period as it would allow more time to review performance throughout the year and allow the Balancing Authority to work through any needed changes.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	

Seasonal performance may cause confusion in evaluating compliance. Is a "Summer" Seasonal ERA to be performed for two summers or spring and summer? If a Fall Seasonal ERA is then performed is it summer and fall or fall and winter? Or fall of year X and fall of year Y? The technical rationale does an excellent job of illustrating the near-term concept and WECC suggests the SDT do the same for seasonal to avoid discussion or confusion after the Standard is enforceable. Compliance risk often causes unwanted scenarios.

The language appears to introduce terms that may not be widely known or understood. For instance- Time series demand—is that forecasted Demand or something different? A thorough scrub to ensure Glossary of Terms usage is correct and meets style guidelines (e.g., Contingency is an approved Glossary of Terms term and is used extensively but not capitalized. Attachment 1 calls out an "Energy contingency" and "Fuel contingency" but those terms are used sparingly—and do not follow style guide to be capitalized in the Standard). "base case"- understood by planners but perhaps not by BAs/RCs.

Part 1.3- Unclear as to what a "base case element " is and what is expected here. The word Element is a defined term in the NERC Glossary. Should it be capitalized here? Part 1.2 says to include all the Part 1.2 subparts. Consider changing Part 1.3 to say "Include a documented rationale for data in Requirement R1.2."

Would 1.2.5 be included in 1.2.3? Technical rationale could illustrate expectations.

Likes 0	
Dislikes 0	
Response	
Richard Gilbert - Florida Reliability Coordinating Council – Member Services Division - 8 - SERC	
Answer	No
Document Name	
Comment	

The process and the required parameters are not clear and understandable.

FRCC's first concern is that this standard only addresses requirements for Balancing Authorities (BAs) and Reliability Coordinators (RCs), but does not allow for Reserve Sharing Groups (RSGs) or collections of BAs to perform these requirements. FRCC, which has an RSG comprised of nine (9) BAs, believes the "Applicability" of the standard should be written more flexibly to allow for BAs *or RSGs or Collection of BAs*. By allowing for RSGs or Collection of BAs, FRCC RC would then be responsible to review ERA processes for one RSG or Collection of BAs, as opposed to nine (9) separate BAs, which is administratively efficient without any sacrifice to reliability. By contrast, without the addition of RSGs or Collection of BAs, the RC would be responsible not only to review the ERA processes for nine (9) separate BAs as well as their corresponding near-term and seasonal time horizon scenarios each time they are run, but also to compile all reviews and responses of each individual entity in order to demonstrate compliance for RC function. The tracking of multiple reviews and responses, along with compiling the evidence to support completion, on this individual basis would cause a significant administrative burden on the RC function. Having nine (9) BAs each submitting individual process documents (and revisions) along with the large number of scenarios would require substantial additions to RC personnel in order to remain in compliance without providing any additional reliability assurances. Moreover, the creation of compliance evidence for the implementation of the ongoing near-term ERAs would be cumbersome due to the large number of studies and their documented scenarios, rationales, and criteria.

As an additional example of the potential burdens the standard imposes on compliance, FRCC notes that, in addition to performing BA and TOP coordinated next-day Operational Planning Analysis along with four (4) seasonal studies, FRCC also performs BA and TOP coordinated 8-day and 28-day studies at least weekly. All studies include at a minimum an N-1 contingency analysis with forecasted load, expected generation output levels, and other known system constraints including generation or facility outages. FRCC currently performs this function without the need to compile burdensome administrative evidence; FRCC is able to instead focus on the study results and development of Operating Plans. If each of the nine (9) BAs in the FRCC RC area were required to independently perform the near-term and seasonal ERAs as described in the proposed standard language, it would result in a constant influx and overabundance of study results for the RC to review. The RC would have to manage this avalanche of additional results fruitlessly, as there would be no improvement in the situational awareness that we currently achieve through our coordinated next-day, 8-day, 28-day, and seasonal assessments.

FRCC also has several concerns with the Near-Term language. FRCC is concerned that, by attempting to provide flexibility (*see R1.1.1.1 and R1.1.1.2*), the frequency and duration requirement language for Near-Term ERAs only leads to confusion. FRCC maintains that the BA or RSG should determine the frequency, duration, and granularity of the ERAs based on area or region. Compounding the potential confusion is that "Near-Term" is not a NERC-defined time horizon (*see excerpt from NERC Time Horizon document below*):

"When establishing a time horizon for each requirement, the following criteria should be used:

1. Long-term Planning – a planning horizon of one year or longer.

2. Operations Planning – operating and resource plans from day-ahead, up to, and including seasonal.

3. Same-day Operations – routine actions required within the timeframe of a day, but not real-time.

4. Real-time Operations – actions required within one hour or less to preserve the reliability of the bulk electric system.

5. Operations Assessment – follow-up evaluations and reporting of real-time operations."

Failing to explicitly define "near term" dooms compliance to failure. Accordingly, FRCC proposes that "Near-Term" be replaced in the standard with the NERC defined term of "**Peak Demand.**" NERC defines Peak Demand in its Glossary of Terms as, "[t]he highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year)." Providing a clear definition of the applicable "Peak Demand" time period (e.g., between next-day to up to one month out from Real-time – the "Monthly Peak Demand Period") could then place borders around the permitted study dates without tying the BA to a specific duration to perform ERAs.

Similarly, "Time Series demand" is neither a NERC defined term, nor is it defined in the standard. Any final standard would require the inclusion of an explicit definition and explanation.

FRCC's final concern relates to the review time. FRCC suggests that a review time of 24 months for the ERA Process would allow adequate time to review performance throughout the year and allow the BA (or RSG) to implement necessary changes.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	

Comment

R1.1.

NPCC RSC supports the BA having the flexibility to determine the time period for the ERAs.

R.1.2.

Based on the standard as drafted, this appears to imply a deterministic assessment. Is a probabilistic assessment permitted? To accommodate alternative ERA approaches, the RSC proposes that the BA determine the type of assessment. As we move into the future, and probabilistic models and analysis become more prevalent, the standard can evolve to reflect generally accepted industry practices.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	Yes
Document Name	

Comment

R1.1.

NPCC RSC supports the BA having the flexibility to determine the time period for the ERAs.

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Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments:

"R1.1.
NPCC RSC supports the BA having the flexibility to determine the time period for the ERAs.
R.1.2.
Based on the standard as drafted, this appears to imply a deterministic assessment. Is a probabilistic assessment permitted? To accommodate alternative ERA approaches, the RSC proposes that the BA determine the type of assessment. As we move into the future, and probabilistic models and analysis become more prevalent, the standard can evolve to reflect generally accepted industry practices."

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2

Answer	Yes
Document Name	

Comment

R1.1.

The IESO supports the BA having the flexibility to determine the time period for the ERAs.

R.1.2.

Based on the standard as drafted, this appears to imply a deterministic assessment. Is a probabilistic assessment permitted? To accommodate alternative ERA approaches, the IESO proposes that the BA determine the type of assessment. As we move into the future, and probabilistic models and analysis become more prevalent, the standard can evolve to reflect generally accepted industry practices

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	Yes
Document Name	

Comment

R1.1.

NPCC RSC supports the BA having the flexibility to determine the time period for the ERAs.

R.1.2.

Based on the standard as drafted, this appears to imply a deterministic assessment. Is a probabilistic assessment permitted? To accommodate alternative ERA approaches, the RSC proposes that the BA determine the type of assessment. As we move into the future, and probabilistic models and analysis become more prevalent, the standard can evolve to reflect generally accepted industry practices.

Likes 0	
Dislikes 0	

Response

Holly Mitchell - NorthWestern Energy - NA - Not Applicable - WECC

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

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 5, 3; Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Requirement Part 1.1.1.1 states that the end of the near-term assessment period shall be greater than five days but does not state the minimum beginning of the near-term assessment period so it is unclear whether the beginning of the near-term assessment starts at the current operating day or after the day ahead. BAs conduct studies for next day operations conditions under TOP-002 (R4), and it does not provide additional insight to conduct extra assessment for day ahead. Texas RE recommends the following language:	

1.1.1.1 The beginning of the near-term assessment shall be at minimum, two days after the current operating day and the end of the near-term assessment period shall be greater than five days and less than six weeks from the start of the assessment (i.e. minimum beginning time for near-term ERA is t0+2 days, where t0 is the operating day)

In Requirement Part 1.1.2.2, Texas RE recommends that the study schedules for Seasonal ERAs should not depend on the mitigation options for each seasonal ERA for schedule consistency and auditability. A lead time of 30 days for completing the seasonal ERA would be appropriate in order to give the BA time review the ERA prior to the beginning of the season. Texas RE recommends the following language:

1.1.2.2 Document a deadline for completing each seasonal ERA at least 30 calendar days prior to the beginning of the season. Mitigation options for each seasonal ERA shall be documented.

In Requirement Part 1.2.3.1, Texas RE requests clarification on the word “flexibility”. Texas RE suggests changing “flexibility” to “uncertainty”. In addition, Texas RE suggests that the BA include any transmission system constraints in the base case in order to have the wide-area view. Texas RE recommends adding the following:

1.2.3.5 All identified transmission system constraints.

Likes 0	
Dislikes 0	

Response

3. The SDT proposes to require a set of scenarios to be developed which is needed in the performance of ERAs. Additionally, there is Attachment 1 that further supports the development of the set of scenarios. Are the scenarios specified in Requirement 2 the correct level or risk to consider in an ERA, and is the development of scenarios clear and understandable? If not, please provide the basis that supports your answer or suggestions for revisions. Please specify if comments are related to the near-term, seasonal ERA, or both.

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

R1.1.2.1, in calling for Energy Reserve Assessments that are, "representative of seasonal risks," invites repeating past mistakes of basing ERAs typical weather conditions. Winter Storm Uri for example brought the weather to hit Texas in 32 years, far beyond the 0.2 percentile cutoff of the EOP-012 ECWT and evidently also out-of-scope for BAL-007 seasonal ERAs. Preventing a repetition of this disaster requires identifying credible statistical outlier (i.e. non-representative) weather conditions. We suggest looking at ASHRAE 50-year return dry bulb temperatures for summer (with zero wind), winter (with zero wind) and looking also at winter with a 20 mph wind.

This will make the BA's job easier, by deriving clear, easily identifiable benchmark conditions from the historical weather record rather than relying on complex and potentially useless theoretical analyses. Winter Storm Uri would have caused little or no difficulty if power generation and fuel supply resources that were added in the affected area during recent decades had been built under the rule that they must be capable of handling a repeat of the winter storm of January 1989 – it's that simple.

Concerns that BAL-007 is too watered-down are amplified by R2 of the standard, which requires making projected (50/50 probability) and high confidence level (90/10) load studies for Att. 1 contingencies regarding energy (loss of the largest energy supply) and fuel (loss of fuel supply that causes the largest reduction in electrical energy supply). These are not adequate stress tests. The Polar Vortex of 2014, Winter Storm Uri, Winter Storm Elliott etc have shown that the essential first step to achieving BES resiliency is identifying the worst credible weather. BAL-007 conclusions regarding generation adequacy will have no grounding if one is not looking at the most serious challenge. Only then can one accurately estimate the worst-case interaction of load, generation outages (many of them, not just the largest unit), fuel supply constraints (potentially area-wide, not just the most important element).

Likes 0	
Dislikes 0	
Response	

Richard Gilbert - Florida Reliability Coordinating Council – Member Services Division - 8 - SERC	
Answer	No
Document Name	
Comment	

FRCC agrees that ERAs should be performed using scenarios and contingencies that are likely to occur or have a history of occurring, but the scenarios identified in Attachment 1 provide no reliability benefit and are not set at the correct level or risk, nor are they necessary to perform a useful ERA.

More specifically, to be useful and make efficient use of BA and RC time and resources, the standard needs to allow either the BA *or RSG* or Collection of BAs to determine the likely contingencies to be studied for the ERA. As written, the Energy Contingencies identified in Attachment 1 only allow for each individual BA to determine and study their likely contingencies; it excludes RSGs or Collection of BAs and the way RSGs or Collection of BAs could operate. If each FRCC BA independently studied the loss of their largest energy supply without the consideration of how the RSG or Collection of BAs functions or the reasonability of a single contingency to take down the entire site, each BA would be documenting mitigation activities not realistic to how the BAs in the FRCC RC area operate.

In addition, the BA *or RSG* or Collection of BAs should determine the appropriate Energy and Fuel contingencies that would yield the most value from the ERA process based on their BA *or RSG* or Collection of BAs area. The Energy Contingency in Attachment 1 is redundant to the Most Severe Single Contingency (MSSC) calculation already required in BAL-002 that is used to determine a BAs' or RSG's or Collection of BAs' Contingency Reserves. Attachment 1 is inconsistent in referencing "single contingencies" in the first paragraph and then "N-1 contingency" in the second paragraph. Some generation sites are designed to not have a single point of failure that would remove all generation output from the site. Again, the BA *or RSG* or Collection of BAs would be best position to know and understand the appropriate contingencies to be studied for an ERA.

Also, it is unrealistic to require performance of the extreme (and unlikely) Fuel Contingency descriptions provided in Attachment 1 on a repetitive cycle for every "near-term" ERA. (As explained previously, FRCC objects to the standard' use of the term "Near-Term," as it is not clearly defined.) Again, this would be an instance in which FRCC BAs would each end up unrealistically considering the loss of an entire gas pipeline outage resulting in the loss of multiple units without any consideration of the RSG or the likelihood of this type of contingency occurring.

As written, this standard would require BAs to create an excessive number of studies to be reviewed and analyzed without providing any additional reliability benefits. Instead, the requirements should allow for BAs *or RSGs* or Collection of BAs to establish and define the assessment scenarios and contingencies as part of their RC reviewed ERA process document and not as a separate R2 requirement creating additional evidence requirements. The standard should not dictate the required number and prescribed scenarios for the ERA, which should be left to the BA *or RSG* or Collection of BAs to incorporate in their RC reviewed process document based on actual conditions in their area. The BA *or RSG* or Collection of BAs should not be required to include high-risk, low-probability scenarios in ERAs performed in the Operations Planning Time Horizon.

In addition, the FRCC believes that the R3 requirement to develop Operating Plan(s) to mitigate unacceptable risk identified in the ERA needs to be addressed along with ERA scenarios and contingency selection concepts in R1 and not be a separate requirement.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	

Comment

In terms of both ERA types- It is not clear if shoulder months with high penetrations of IBRs will be captured. Parts 2.1.1, 2.1.2, and 2.1.3 seem to consider the possibilities but may not capture the variability aspects of the IBR fleets. Based on the proposed (are they proposed?) definitions of "Energy contingency" and "fuel contingency" (the word "Contingency" is a defined term in the Glossary. Should it be capitalized here?) the variability may not be captured. Using "a single Contingency" within "Energy contingency" limits the impact to that definition—" The unexpected failure or outage of (add **"a system component")**, such as a generator, transmission line, circuit breaker, switch or other electrical element" and does not necessarily capture multiple outages of solar, wind, or battery installations that only last a short time (that will be the compliance risk approach presented by entities). If a single Contingency (e.g., fault causing loss of transmission line and resulting low voltage), causes the loss of a large number of IBRs but most return to service in minutes the MWh impact may be minimal in either ERA scenario.

Likes 0	

Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	

Black Hills Corporation agrees with EEI's comments: While EEI agrees that ERAs should be performed using scenarios and contingencies that are likely to occur or have a history of occurring, we do not agree that the scenarios in requirement R2 are the correct level of risk within the Operations Planning Horizon nor that the scenarios are clear and understandable. We suggest that the SDT consider incorporating scenario development within Requirement R1.

We also do support the proposed number and prescription in BAL-007-1 for the scenarios, noting the statement on page 4 of the SAR, "*For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Instead, each entity will establish and document criteria as part of complying with the Standard*." While we support that the scenarios should contain contingencies related to demand, energy, and fuel considerations; the BA should be afforded the latitude to determine what is reasonable to include within the Operations Time Horizon. The BA should also not be required to include high-risk, low-probability scenarios in their ERAs.

We are also concerned that as written this requirement would require more BA resources in order to create the large number of studies being proposed and question whether these studies would provide the desired reliability benefit. Moreover, requiring a specific number and type of scenarios to be analyzed in each time-step of the ERA process could result excessive amounts of data that could produce "false positives" that would make it difficult to determine when the BA should act.

We further question the usefulness of the Attachment 1 and the identified contingencies because it is unclear whether they add any reliability benefits or provide any utility in developing useful ERAs. The energy contingency in Attachment 1 also appears to be redundant to the Most Severe Single Contingency (MSSC) calculation already required in BAL-002 which is used to determine a Balancing Authority's Contingency Reserves. It is also important to recognize that the fuel contingency in Attachment 1 would only be as useful as the Balancing Authority's visibility into fuel supply information. We agree that the BA should determine the energy and fuel contingencies that would yield the most value from the ERA process for their geographic region and market structure but see little value in what is provided in Attachment 1. For this reason, we ask the SDT to consider removing Attachment 1 from this standard.

Finally, the R3 requirement to develop Operating Plan(s) to mitigate unacceptable risk identified in the ERA needs to be addressed along with ERA scenarios. The SDT made it clear that these Operating Plans should be specific to the new BAL-007 standard and would not overlap or conflict with existing Operating Plan(s) already required in TOP-002-4 R4 Next Day, BAL-002 R2 MSSC Contingency Reserves, and EOP-011-2 R2 Energy and Capacity Emergencies. However, this standard does not provide the BA with any authority to mitigate FORECASTED energy emergencies. This limits the actions a BA can take in BAL-007 to increased study frequency, communication with generators and other relevant entities, requesting that the RC take action such as moving generation outages, or identifying existing Operating Plans that would be enacted should the risk of an actual energy emergency become imminent. With this in mind, we suggest that the SDT consider reducing the scope of requirement R3 and making it a sub requirement of R1. We additionally ask the SDT to consider changing the requirement to the development of strategic actions that would minimize the risks associated with energy emergencies that the BA could reasonably take up to and including the identification of existing Operating Plans, should a forecasted energy emergency become an actual energy emergency.

To address these concerns, we offer the following changes to Requirements R1, R2 and R3 for SDT consideration (changes in boldface):

R1.

1.4. Include a documented set of Balancing Authority determined ERA scenarios to be considered that include the following:

1.4.1. The Projected System Load

1.4.2. Energy and/or Fuel contingencies

1.4.3. Any event that is projected or likely to occur.

1.4.4. How these contingencies are considered.

1.5 Include a documented rationale for scenarios chosen in Requirement R1.4

1.6 Develop and document mitigating actions that could be used to mitigate unacceptable risk(s) identified by the results of an ERA. Such actions may include but are not limited to:

1.6.1. Increase ERA study frequency.

1.6.2. Communicate with generators concerning fuel sources.

1.6.3. Request the RC to take specific action.

1.6.4. Identify existing Operating Plan(s) that would be informed by the ERA results should the forecasted energy emergency become an actual emergency.

(*remove R2 and R3:*

R2. Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed ERA scenarios for both the near-term and seasonal time horizons, as follows: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R3. Each Balancing Authority shall develop, maintain, and document one or more Operating Plan(s) to mitigate unacceptable risk(s) associated with ERA scenario(s) with a likely event of occurring. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning])

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NSRF observes that the Attachment 1 scenarios are reminiscent and duplicative of those prescribed under EOP-011 and TOP-002, Requirement R8. In addition, the scenarios recommended may not capture those that are the highest risk for each BA. Therefore, each BA should be able to determine the scenarios relevant to ensuring reliable operations in its footprint. The standard should accommodate alternative approaches which may be equally as good or superior. Examples could be provided in the Technical Rationale.

Additional commentary regarding the contingencies in BAL-007-1, Attachment 1:

• Energy contingency – The MRO NSRF supports a more dynamic definition like the one in BAL-007.

• Fuel Assurance – The MRO NSRF views the requirement to utilize a 'bottom-up" approach, based on fuel, as overly prescriptive and administratively burdensome. The proposed approach will be challenging to implement and may not translate into real reliability benefits, particularly since there is no requirement for Generator Operators to provide the fuel information. BAs will not know the finite fuel information for each generating unit without the unit having an obligation to provide it.

In addition, requiring BAs to become intimately familiar with gas pipeline operations takes time and effort away from managing electric system operations. For BAs with many pipelines in their footprint, gathering and maintaining this information will be fraught with error and for what purpose? Focusing solely on loss of fuel to the exclusion of other relevant factors (e.g. unplanned outages caused by equipment failures) leads to poor and inaccurate results.

The standard should be written to accommodate a variety of modeling approaches (scenarios, stochastic, deterministic, probabilistic, etc.) so it doesn't need to be revised with technology advancements.

Example: One BA sets its reserve margin threshold based on quantified Net Uncertainties and predicted daily risk profiles. The Net Uncertainty is quantified based on the historical distribution at specified confidence levels, accounting for load, wind and solar forecast errors, thermal generation availability and interchange changes between Next-Day projection and Real-Time actual. A machine learning model is used to predict the daily risk profile at High/Medium/Low levels based on what was experienced in historical like-weather and operating conditions.
This dynamic, data-driven method is more reliable and efficient to manage varying system conditions instead of static administrative values which can become stagnant.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	No
Document Name	

Comment

R2.1

Is high load left up to each BA to define?

The SDT want may consider adding some specificity in the Technical Rationale regarding the load levels or range of load levels, and solar, wind, water or other variable or uncontrolled fuel resources that must be assessed over the assessment period, for example:

- use the mean energy demand profile over the assessment period for the system normal condition,
- use the xxth percentile, or nth standard deviations above the median energy demand profile for the high demand condition.
- use the xxth percentile, or nth standard deviation below the median profile for the energy supplied from one or more variable fuel sources for the fuel supply contingency or for scenario 2.1.7

As the proposed ERA scenarios may seem too stringent, the RSC proposes that the BAs could determine the ERA scenarios that are relevant to their area. If a minimum set of contingencies need to be set, the RSC suggest the following as a starting point:

- a high energy demand with the single largest energy production source

- a median (or not as high) energy demand scenario with the fuel contingency that interrupts multiple units and represents the largest total energy supply.

We would still suggest that the assessment include an accounting of the total energy from each resource type and the resulting capacity factor of these resources in the high load or contingency scenarios, to assess whether there is high confidence that their higher capacity factors are achievable.

R3.

Operating Plans may be misconstrued to mean actions that would be implemented in near real-time or during an emergency. Please clarify that the intent is that these Operating Plans are more like mitigation measures that must be implemented far in advance as is necessary to make them effective in mitigating potential energy deficiencies. We suggest replacing ‘Operating Plan(s)’ with **‘mitigation measure(s)**.’

In addition, we disagree with the example in the **Technical Rationale** that Operating Plans might include load shedding. Plans could include:

- dispatching resources such that limited fuel resources conserve fuel during low demand periods for use in higher demand periods.,
- re-scheduling of maintenance outages to make more energy resources available,
- instructing generators to order more fuel, increase fuel supplies, or firm up fuel deliveries to the extent contracts allow;

however, the plans should **exclude actions such as relying on voltage reductions or load shedding.** These are considered emergency procedures and should not be permitted in longer-term operating plans (longer-term plans shouldn’t rely on having to use emergency procedures -- they should be reserved for unplanned emergency situations).

R2.1.3: Replace “fuel” contingency by “resource” contingency

R2.1.7: what is the criteria for determining whether a historical event falls under this criterion?

R4: this requirement seems superfluous as it is implied in R1 and R2 that the ERA process is RC reviewed.

R1 to R3 : a deadline should be established in the agreed upon process.

R7 : the BA shall also develop, maintain and document an operation plan to mitigate unacceptable risk associate with the ERA scenario that is required in R3 if there is an issue.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports the comments submitted by EEI.

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 supports the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment

Exelon supports the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Duke Energy supports and recommends implementation of EEI provided comments.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

“See comments submitted by the Edison Electric Institute”

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

Manitoba Hydro is supportive of comments provided by the MRO NSRF. For the Manitoba system, the different system conditions (prior outages, loading, generation scheduling) might result in a different single large energy contingency or critical contingencies. For other utilities, the different systems require different focuses when performing the ERA to address the issues. The standard should accommodate modelling improvements or alternative approaches to modelling uncertainties to ensure the BA is performing ERAs that are best suited to their area.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	

Comment

PNMR supports EEI’s recommended changes to R1, R2, and R3 provided in their response.

Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
BC Hydro suggests that BAs should have the ability to determine the relevant scenarios to ensuring reliable operations based on prevailing operating conditions operational experience in their respective footprints. The Technical Rationale would be the appropriate location for possible ways to derive relevant scenarios rather than being prescribed within the Requirement.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
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; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
The scenarios in BAL-007 are reminiscent and duplicative of those already prescribed under existing standards (EOP-011 and TOP-002, Requirement R8) and should not be prescribed in BAL-007. Instead, the BA should have the ability to determine the scenarios relevant to ensuring reliable operations in its footprint. This would better accommodate alternative approaches, such as the Western Power Pool's WRAP. Examples of what scenarios could be	

considered in an ERA should still be provided in the Technical Rationale or an Implementation Guide. Tacoma Power supports moving the examples from the Standard to these guidance documents.	
Likes 2	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia; American Municipal Power, 5, Ritts Amy
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Florida Power & Light does not agree that the scenarios in requirement R2 are the correct level of risk for within the Operations Planning Horizon nor that the scenarios are clear and understandable. First, the BA should determine what is reasonable to include within the Operations Time Horizon. The BA should not be required to include high-risk, low-probability scenarios in their ERAs. Third, as written this requirement would require more BA resources to create an excessive number of studies without an additional reliability benefit. The proposed standard is redundant, specifically regarding to the Most Severe Single Contingency (MSSC) calculation already required in BAL-002 which is used to determine a Balancing Authority's Contingency Reserves. The Fuel Contingency in Attachment 1 would only be as useful as the Balancing Authority's visibility to fuel supply information. The SDT made it clear that these Operating Plans should be specific to the new BAL-007 standard and would not overlap or conflict with existing Operating Plan(s) already required in TOP-002-4 R4 Next Day, BAL-002 R2 MSSC Contingency Reserves, and EOP-011-2 R2 Energy and Capacity Emergencies however they clearly do overlap.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	

Answer	No
Document Name	

Comment

R2.1

Is high load left up to each BA to define?

The SDT want may consider adding some specificity in the Technical Rationale regarding the load levels or range of load levels, and solar, wind, water or other variable or uncontrolled fuel resources that must be assessed over the assessment period, for example:

· use the mean energy demand profile over the assessment period for the system normal condition,

. use the xxth percentile, or nth standard deviations above the median energy demand profile for the high demand condition

· use the xxth percentile, or nth standard deviation below the median profile for the energy supplied from one or more variable fuel sources for the fuel supply contingency or for scenario 2.1.7

As the proposed ERA scenarios may seem too stringent, the IESO proposes that the BAs have the ability to determine the ERA scenarios that are relevant to their area. If a minimum set of contingencies need to be set, the IESO suggest the following as a starting point:

· a high energy demand with the single largest energy production source

· a median (or not as high) energy demand scenario with the fuel contingency that interrupts multiple units and represents the largest total energy supply.

We would still suggest that the assessment include an accounting of the total energy from each resource type and the resulting capacity factor of these resources in the high load or contingency scenarios, to assess whether there is high confidence that their higher capacity factors are achievable.

R3.

Operating Plans may be misconstrued to mean actions that would be implemented in near real-time or during an emergency. Please clarify that the intent is that these Operating Plans are more like mitigation measures that must be implemented far in advance as is necessary to make them effective in mitigating potential energy deficiencies. We suggest replacing 'Operating Plan(s)' with **'mitigation measure(s)**.'

In addition, we disagree with the example in the **Technical Rationale** that Operating Plans might include load shedding. Plans could include:

· dispatching resources such that limited fuel resources conserve fuel during low demand periods for use in higher demand periods.,

· re-scheduling of maintenance outages to make more energy resources available,

· instructing generators to order more fuel, increase fuel supplies, or firm up fuel deliveries to the extent contracts allow;

however, the plans should **exclude actions such as relying on voltage reductions or load shedding.** These are considered emergency procedures and should not be permitted in longer-term operating plans (longer-term plans shouldn't rely on having to use emergency procedures -- they should be reserved for unplanned emergency situations).

Likes 0	

Dislikes 0	

Response

Dania Colon - Orlando Utilities Commission - 5	
Answer	No
Document Name	

Comment
The scenarios identified in Attachment 1 are not at the correct level or risk. FRCC agrees that ERAs should be performed using scenarios and contingencies that are likely to occur or have a history of occurring. However, we do not agree to the scenarios in requirement R2 are the correct level or risk within the Operations Planning Horizon. In addition to the overall standard not taking into account Reserve Sharing Groups, the Energy Contingencies identified in Attachment 1 do not acknowledge how Reserve Sharing Groups operate. If each BA was required to independently study the loss of their largest energy supply without the consideration of how the Reserve Sharing Group functions, each BA would be documenting mitigation activities not realistic to how the BAs in the FRCC RC area operate. The requirements should allow for BAs or RSGs to establish and define the assessment scenarios and contingencies as part of their RC reviewed ERA process document. The Energy Contingency also states that the contingency may not persist through the entire assessment period. This is unclear. In addition, the Fuel Contingency descriptions provided in Attachment 1 are unrealistic to perform on a repetitive cycle for every near-term ERA. As stated, FRCC BAs would each have to consider the loss of an entire gas pipeline outage resulting in the loss of multiple units without the consideration of a Reserve Sharing Group and the likelihood of this type of contingency occurring. It also does not take into account that some generation sites are dual fueled. Again, the language in this contingency description stating that the contingency may not persist through the entire assessment period is unclear. As written, this requirement would require BAs to create an excessive number of studies to be reviewed and analyzed without reliability benefit. Requiring the specific types of scenarios outlined in this standard to be built on a continuous basis would result in volumes of data to be analyzed and not allow for the appropriate development of Operating Plans to address realistic reliability issues.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	

Comment
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the MRO NSRF for question #3.

Likes 0	
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 5, 3; Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Buckeye supports the comments made by ACES:

It is our opinion that specific scenarios should not be included in the Reliability Standard. We believe that by doing so, it makes the Reliability Standard too prescriptive and limits the ability of the BA to appropriately develop specific scenarios for their Balancing Authority Area and the unique challenges encountered therein

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments:

"R2.1

Is high load left up to each BA to define?

The SDT want may consider adding some specificity in the Technical Rationale regarding the load levels or range of load levels, and solar, wind, water or other variable or uncontrolled fuel resources that must be assessed over the assessment period, for example:

• use the mean energy demand profile over the assessment period for the system normal condition,

• use the xxth percentile, or nth standard deviations above the median energy demand profile for the high demand condition.

• use the xxth percentile, or nth standard deviation below the median profile for the energy supplied from one or more variable fuel sources for the fuel supply contingency or for scenario 2.1.7

As the proposed ERA scenarios may seem too stringent, the RSC proposes that the BAs could determine the ERA scenarios that are relevant to their area. If a minimum set of contingencies need to be set, the RSC suggest the following as a starting point:

• a high energy demand with the single largest energy production source

• a median (or not as high) energy demand scenario with the fuel contingency that interrupts multiple units and represents the largest total energy supply.

We would still suggest that the assessment include an accounting of the total energy from each resource type and the resulting capacity factor of these resources in the high load or contingency scenarios, to assess whether there is high confidence that their higher capacity factors are achievable.

R3.

Operating Plans may be misconstrued to mean actions that would be implemented in near real-time or during an emergency. Please clarify that the intent is that these Operating Plans are more like mitigation measures that must be implemented far in advance as is necessary to make them effective in mitigating potential energy deficiencies. We suggest replacing 'Operating Plan(s)' with **'mitigation measure(s)**.'

In addition, we disagree with the example in the **Technical Rationale** that Operating Plans might include load shedding. Plans could include:

• dispatching resources such that limited fuel resources conserve fuel during low demand periods for use in higher demand periods.,

• re-scheduling of maintenance outages to make more energy resources available,

• instructing generators to order more fuel, increase fuel supplies, or firm up fuel deliveries to the extent contracts allow;

however, the plans should **exclude actions such as relying on voltage reductions or load shedding.** These are considered emergency procedures and should not be permitted in longer-term operating plans (longer-term plans shouldn't rely on having to use emergency procedures -- they should be reserved for unplanned emergency situations)."

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP proposes that the BA should have the ability to determine the ERA scenarios relevant to ensuring reliable operations in its footprint. Examples could still be provided in the Technical Rationale to support the relevancy of the requirements.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5	
Answer	No
Document Name	
Comment	

R2.1

Is high load left up to each BA to define?

The SDT want may consider adding some specificity in the Technical Rationale regarding the load levels or range of load levels, and solar, wind, water or other variable or uncontrolled fuel resources that must be assessed over the assessment period, for example:

{C}· use the mean energy demand profile over the assessment period for the system normal condition,

{C}· use the xxth percentile, or nth standard deviations above the median energy demand profile for the high demand condition.

{C}· use the xxth percentile, or nth standard deviation below the median profile for the energy supplied from one or more variable fuel sources for the fuel supply contingency or for scenario 2.1.7

As the proposed ERA scenarios may seem too stringent, the RSC proposes that the BAs could determine the ERA scenarios that are relevant to their area. If a minimum set of contingencies need to be set, the RSC suggest the following as a starting point:

{C}· a high energy demand with the single largest energy production source

{C}· a median (or not as high) energy demand scenario with the fuel contingency that interrupts multiple units and represents the largest total energy supply.

We would still suggest that the assessment include an accounting of the total energy from each resource type and the resulting capacity factor of these resources in the high load or contingency scenarios, to assess whether there is high confidence that their higher capacity factors are achievable.

R3.

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In addition, we disagree with the example in the **Technical Rationale** that Operating Plans might include load shedding. Plans could include:

{C}· dispatching resources such that limited fuel resources conserve fuel during low demand periods for use in higher demand periods.,

{C}· re-scheduling of maintenance outages to make more energy resources available, {C}·	instructing generators to order more fuel, increase fuel supplies, or firm up fuel deliveries to the extent contracts allow;

however, the plans should **exclude actions such as relying on voltage reductions or load shedding.** These are considered emergency procedures and should not be permitted in longer-term operating plans (longer-term plans shouldn't rely on having to use emergency procedures -- they should be reserved for unplanned emergency situations).

R2.1.3: Replace "fuel" contingency by "resource" contingency

R2.1.7: what is the criteria for determining whether a historical event falls under this criterion?

R4: this requirement seems superfluous as it is implied in R1 and R2 that the ERA process is RC reviewed.

R1 to R3 : a deadline should be established in the agreed upon process.

R7 : the BA shall also develop, maintain and document an operation plan to mitigate unacceptable risk associate with the ERA scenario that is required in R3 if there is an issue.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

SMUD and BANC support the comments submitted by Tacoma Power.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

While EEI agrees that ERAs should be performed using scenarios and contingencies that are likely to occur or have a history of occurring, we do not agree that the scenarios in requirement R2 are the correct level of risk within the Operations Planning Horizon nor that the scenarios are clear and understandable. We suggest that the SDT consider incorporating scenario development within Requirement R1.

We also do support the proposed number and prescription in BAL-007-1 for the scenarios, noting the statement on page 4 of the SAR, "*For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Instead, each entity will establish and document criteria as part of complying with the Standard*." While we support that the scenarios should contain contingencies related to demand, energy, and fuel considerations; the BA should be afforded the latitude to determine what is reasonable to include within the Operations Time Horizon. The BA should also not be required to include high-risk, low-probability scenarios in their ERAs.

We are also concerned that as written this requirement would require more BA resources in order to create the large number of studies being proposed and question whether these studies would provide the desired reliability benefit. Moreover, requiring a specific number and type of scenarios to be analyzed in each time-step of the ERA process could result excessive amounts of data that could produce "false positives" that would make it difficult to determine when the BA should act.

We further question the usefulness of the Attachment 1 and the identified contingencies because it is unclear whether they add any reliability benefits or provide any utility in developing useful ERAs. The energy contingency in Attachment 1 also appears to be redundant to the Most Severe Single Contingency (MSSC) calculation already required in BAL-002 which is used to determine a Balancing Authority's Contingency Reserves. It is also important to recognize that the fuel contingency in Attachment 1 would only be as useful as the Balancing Authority's visibility into fuel supply information. We agree that the BA should determine the energy and fuel contingencies that would yield the most value from the ERA process for their geographic region and market structure but see little value in what is provided in Attachment 1. For this reason, we ask the SDT to consider removing Attachment 1 from this standard.

Finally, the R3 requirement to develop Operating Plan(s) to minimize unacceptable risk identified in the ERA needs to be addressed along with ERA scenarios. The SDT made it clear that these Operating Plans should be specific to the new BAL-007 standard and would not overlap or conflict with existing Operating Plan(s) already required in TOP-002-4 R4 Next Day, BAL-002 R2 MSSC Contingency Reserves, and EOP-011-2 R2 Energy and Capacity Emergencies. However, this standard does not provide the BA with any authority to minimize forecasted energy emergencies. This limits the actions a BA can take in BAL-007 to increased study frequency, communication with generators and other relevant entities, requesting that the RC take action such as moving generation outages, or identifying existing Operating Plans that would be enacted should the risk of an actual energy emergency become imminent. With this in mind, we suggest that the SDT consider reducing the scope of requirement R3 and making it a sub requirement of R1. We additionally ask the SDT to consider changing the requirement to the development of strategic actions that would minimize the risks associated with energy emergencies that the BA could reasonably take up to and including the identification of existing Operating Plans, should a forecasted energy emergency become an actual energy emergency.

To address these concerns, we offer the following changes to Requirements R1, R2 and R3 for SDT consideration (changes in boldface):

R1.

{C}**1.4. Include a documented set of Balancing Authority determined ERA scenarios to be considered that include the following:**

{C}**1.4.1. The Projected System Load**

1.4.2. Energy and/or Fuel contingencies

1.4.3. Any event that is projected or likely to occur.

1.4.4. How these contingencies are considered.

1.5 Include a documented rationale for scenarios chosen in Requirement R1.4

1.6 Develop and document actions that could be used to minimize unacceptable risk(s) identified by the results of an ERA. Such actions may include but are not limited to:

1.6.1. Increase ERA study frequency.

1.6.2. Communicate with generators concerning fuel sources.

1.6.3. Request the RC to take specific action.

1.6.4. Identify existing Operating Plan(s) that would be informed by the ERA results should the forecasted energy emergency become an actual emergency.

R2. Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed ERA scenarios for both the near-term and seasonal time horizons, as follows: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R3. Each Balancing Authority shall develop, maintain, and document one or more Operating Plan(s) to mitigate unacceptable risk(s) associated with ERA scenario(s) with a likely event of occurring. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	

Comment

While EEI agrees that ERAs should be performed using scenarios and contingencies that are likely to occur or have a history of occurring, we do not agree that the scenarios in requirement R2 are the correct level of risk within the Operations Planning Horizon nor that the scenarios are clear and understandable. We suggest that the SDT consider incorporating scenario development within Requirement R1.

We also do support the proposed number and prescription in BAL-007-1 for the scenarios, noting the statement on page 4 of the SAR, "*For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Instead, each entity will establish and document criteria as part of complying with the Standard*." While we support that the scenarios should contain contingencies related to demand, energy, and fuel considerations; the BA should be afforded the latitude to determine what is reasonable to include within the Operations Time Horizon. The BA should also not be required to include high-risk, low-probability scenarios in their ERAs.

We are also concerned that as written this requirement would require more BA resources in order to create the large number of studies being proposed and question whether these studies would provide the desired reliability benefit. Moreover, requiring a specific number and type of scenarios to be analyzed in each time-step of the ERA process could result excessive amounts of data that could produce "false positives" that would make it difficult to determine when the BA should act.

We further question the usefulness of the Attachment 1 and the identified contingencies because it is unclear whether they add any reliability benefits or provide any utility in developing useful ERAs. The energy contingency in Attachment 1 also appears to be redundant to the Most Severe Single Contingency (MSSC) calculation already required in BAL-002 which is used to determine a Balancing Authority's Contingency Reserves. It is also important to recognize that the fuel contingency in Attachment 1 would only be as useful as the Balancing Authority's visibility into fuel supply information. We agree that the BA should determine the energy and fuel contingencies that would yield the most value from the ERA process for their geographic region and market structure but see little value in what is provided in Attachment 1. For this reason, we ask the SDT to consider removing Attachment 1 from this standard.

Finally, the R3 requirement to develop Operating Plan(s) to minimize unacceptable risk identified in the ERA needs to be addressed along with ERA scenarios. The SDT made it clear that these Operating Plans should be specific to the new BAL-007 standard and would not overlap or conflict with existing Operating Plan(s) already required in TOP-002-4 R4 Next Day, BAL-002 R2 MSSC Contingency Reserves, and EOP-011-2 R2 Energy and Capacity Emergencies. However, this standard does not provide the BA with any authority to minimize forecasted energy emergencies. This limits the actions a BA can take in BAL-007 to increased study frequency, communication with generators and other relevant entities, requesting that the RC take action such as moving generation outages, or identifying existing Operating Plans that would be enacted should the risk of an actual energy emergency become imminent. With this in mind, we suggest that the SDT consider reducing the scope of requirement R3 and making it a sub requirement of R1. We additionally ask the SDT to consider changing the requirement to the development of strategic actions that would minimize the risks associated with energy emergencies that the BA could reasonably take up to and including the identification of existing Operating Plans, should a forecasted energy emergency become an actual energy emergency.

To address these concerns, we offer the following changes to Requirements R1, R2 and R3 for SDT consideration (changes in boldface):

R1.

{C}**1.4. Include a documented set of Balancing Authority determined ERA scenarios to be considered that include the following:**

{C}**1.4.1. The Projected System Load**

1.4.2. Energy and/or Fuel contingencies

1.4.3. Any event that is projected or likely to occur.

1.4.4. How these contingencies are considered.

1.5 Include a documented rationale for scenarios chosen in Requirement R1.4

1.6 Develop and document actions that could be used to minimize unacceptable risk(s) identified by the results of an ERA. Such actions may include but are not limited to:

1.6.1. Increase ERA study frequency.

1.6.2. Communicate with generators concerning fuel sources.

1.6.3. Request the RC to take specific action.

1.6.4. Identify existing Operating Plan(s) that would be informed by the ERA results should the forecasted energy emergency become an actual emergency.

REMOVE THIS..R2. Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed ERA scenarios for both the near-term and seasonal time horizons, as follows: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

REMOVE THIS R3. Each Balancing Authority shall develop, maintain, and document one or more Operating Plan(s) to mitigate unacceptable risk(s) associated with ERA scenario(s) with a likely event of occurring. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

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	

R2.1

Is high load left up to each BA to define?

The SDT want may consider adding some specificity in the Technical Rationale regarding the load levels or range of load levels, and solar, wind, water or other variable or uncontrolled fuel resources that must be assessed over the assessment period, for example:

-use the mean energy demand profile over the assessment period for the system normal condition,

-use the xxth percentile, or nth standard deviations above the median energy demand profile for the high demand condition.

-use the xxth percentile, or nth standard deviation below the median profile for the energy supplied from one or more variable fuel sources for the fuel supply contingency or for scenario 2.1.7

As the proposed ERA scenarios may seem too stringent, the RSC proposes that the BAs could determine the ERA scenarios that are relevant to their area. If a minimum set of contingencies need to be set, the RSC suggest the following as a starting point:

-a high energy demand with the single largest energy production source

-a median (or not as high) energy demand scenario with the fuel contingency that interrupts multiple units and represents the largest total energy supply.

We would still suggest that the assessment include an accounting of the total energy from each resource type and the resulting capacity factor of these resources in the high load or contingency scenarios, to assess whether there is high confidence that their higher capacity factors are achievable.

R3.

Operating Plans may be misconstrued to mean actions that would be implemented in near real-time or during an emergency. Please clarify that the intent is that these Operating Plans are more like mitigation measures that must be implemented far in advance as is necessary to make them effective in mitigating potential energy deficiencies. We suggest replacing 'Operating Plan(s)' with **'mitigation measure(s)**.'

In addition, we disagree with the example in the **Technical Rationale** that Operating Plans might include load shedding. Plans could include:

-dispatching resources such that limited fuel resources conserve fuel during low demand periods for use in higher demand periods.,

-re-scheduling of maintenance outages to make more energy resources available,

-instructing generators to order more fuel, increase fuel supplies, or firm up fuel deliveries to the extent contracts allow;

however, the plans should **exclude actions such as relying on voltage reductions or load shedding.** These are considered emergency procedures and should not be permitted in longer-term operating plans (longer-term plans shouldn't rely on having to use emergency procedures -- they should be reserved for unplanned emergency situations).

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

While NV Energy agrees that ERAs should be performed using scenarios and contingencies that are likely to occur or have a history of occurring, we do not agree that the scenarios in requirement R2 are the correct level of risk within the Operations Planning Horizon nor that the scenarios are clear and understandable. We suggest that the SDT consider incorporating scenario development within Requirement R1.

We also do support the proposed number and prescription in BAL-007-1 for the scenarios, noting the statement on page 4 of the SAR, "*For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Instead, each entity will establish and document criteria as part of complying with the Standard*." While we support that the scenarios should contain contingencies related to demand, energy, and fuel considerations; the BA should be afforded the latitude to determine what is reasonable to include within the Operations Time Horizon. The BA should also not be required to include high-risk, low-probability scenarios in their ERAs.

We are also concerned that as written this requirement would require more BA resources in order to create the large number of studies being proposed and question whether these studies would provide the desired reliability benefit. Moreover, requiring a specific number and type of scenarios to be analyzed in each time-step of the ERA process could result excessive amounts of data that could produce “false positives” that would make it difficult to determine when the BA should act.

We further question the usefulness of the Attachment 1 and the identified contingencies because it is unclear whether they add any reliability benefits or provide any utility in developing useful ERAs. The energy contingency in Attachment 1 also appears to be redundant to the Most Severe Single Contingency (MSSC) calculation already required in BAL-002 which is used to determine a Balancing Authority’s Contingency Reserves. It is also important to recognize that the fuel contingency in Attachment 1 would only be as useful as the Balancing Authority’s visibility into fuel supply information. We agree that the BA should determine the energy and fuel contingencies that would yield the most value from the ERA process for their geographic region and market structure but see little value in what is provided in Attachment 1. For this reason, we ask the SDT to consider removing Attachment 1 from this standard.

Finally, the R3 requirement to develop Operating Plan(s) to mitigate unacceptable risk identified in the ERA needs to be addressed along with ERA scenarios. The SDT made it clear that these Operating Plans should be specific to the new BAL-007 standard and would not overlap or conflict with existing Operating Plan(s) already required in TOP-002-4 R4 Next Day, BAL-002 R2 MSSC Contingency Reserves, and EOP-011-2 R2 Energy and Capacity Emergencies. However, this standard does not provide the BA with any authority to mitigate forecasted energy emergencies. This limits the actions a BA can take in BAL-007 to increased study frequency, communication with generators and other relevant entities, requesting that the RC take action such as moving generation outages, or identifying existing Operating Plans that would be enacted should the risk of an actual energy emergency become imminent. With this in mind, we suggest that the SDT consider reducing the scope of requirement R3 and making it a sub requirement of R1. We additionally ask the SDT to consider changing the requirement to the development of strategic actions that would minimize the risks associated with energy emergencies that the BA could reasonably take up to and including the identification of existing Operating Plans, should a forecasted energy emergency become an actual energy emergency.

To address these concerns, we offer the following changes to Requirements R1, R2 and R3 for SDT consideration (changes in boldface):

R1.

{C}**1.4. Include a documented set of Balancing Authority determined ERA scenarios to be considered that include the following:**

{C}**1.4.1. The Projected System Load**

1.4.2. Energy and/or Fuel contingencies

1.4.3. Any event that is projected or likely to occur.

1.4.4. How these contingencies are considered.

1.5 Include a documented rationale for scenarios chosen in Requirement R1.4

1.6 Develop and document mitigating actions that could be used to mitigate unacceptable risk(s) identified by the results of an ERA. Such actions may include but are not limited to:

1.6.1. Increase ERA study frequency.

1.6.2. Communicate with generators concerning fuel sources.

1.6.3. Request the RC to take specific action.

1.6.4. Identify existing Operating Plan(s) that would be informed by the ERA results should the forecasted energy emergency become an actual emergency.

R2. Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed ERA scenarios for both the near-term and seasonal time horizons, as follows: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

R3. Each Balancing Authority shall develop, maintain, and document one or more Operating Plan(s) to mitigate unacceptable risk(s) associated with ERA scenario(s) with a likely event of occurring. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]	
Likes 0	
Dislikes 0	
Response	
Aaron Staley - Orlando Utilities Commission - 1	
Answer	No
Document Name	
Comment	
See Tacoma Power comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

While EEI agrees that ERAs should be performed using scenarios and contingencies that are likely to occur or have a history of occurring, we do not agree that the scenarios in requirement R2 are the correct level of risk within the Operations Planning Horizon nor that the scenarios are clear and understandable. We suggest that the SDT consider incorporating scenario development within Requirement R1.

We also do support the proposed number and prescription in BAL-007-1 for the scenarios, noting the statement on page 4 of the SAR, "*For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Instead, each entity will establish and document criteria as part of complying with the Standard*." While we support that the scenarios should contain contingencies related to demand, energy, and fuel considerations; the BA should be afforded the latitude to determine what is reasonable to include within the Operations Time Horizon. The BA should also not be required to include high-risk, low-probability scenarios in their ERAs.

We are also concerned that as written this requirement would require more BA resources in order to create the large number of studies being proposed and question whether these studies would provide the desired reliability benefit. Moreover, requiring a specific number and type of scenarios to be analyzed in each time-step of the ERA process could result excessive amounts of data that could produce "false positives" that would make it difficult to determine when the BA should act.

We further question the usefulness of the Attachment 1 and the identified contingencies because it is unclear whether they add any reliability benefits or provide any utility in developing useful ERAs. The energy contingency in Attachment 1 also appears to be redundant to the Most Severe Single Contingency (MSSC) calculation already required in BAL-002 which is used to determine a Balancing Authority's Contingency Reserves. It is also important to recognize that the fuel contingency in Attachment 1 would only be as useful as the Balancing Authority's visibility into fuel supply information. We agree that the BA should determine the energy and fuel contingencies that would yield the most value from the ERA process for their geographic region and market structure but see little value in what is provided in Attachment 1. For this reason, we ask the SDT to consider removing Attachment 1 from this standard.

Finally, the R3 requirement to develop Operating Plan(s) to minimize unacceptable risk identified in the ERA needs to be addressed along with ERA scenarios. The SDT made it clear that these Operating Plans should be specific to the new BAL-007 standard and would not overlap or conflict with existing Operating Plan(s) already required in TOP-002-4 R4 Next Day, BAL-002 R2 MSSC Contingency Reserves, and EOP-011-2 R2 Energy and Capacity Emergencies. However, this standard does not provide the BA with any authority to minimize forecasted energy emergencies. This limits the actions a BA can take in BAL-007 to increased study frequency, communication with generators and other relevant entities, requesting that the RC take action such as moving generation outages, or identifying existing Operating Plans that would be enacted should the risk of an actual energy emergency become imminent. With this in mind, we suggest that the SDT consider reducing the scope of requirement R3 and making it a sub requirement of R1. We additionally ask the SDT to consider changing the requirement to the development of strategic actions that would minimize the risks associated with energy emergencies that the BA could reasonably take up to and including the identification of existing Operating Plans, should a forecasted energy emergency become an actual energy emergency.

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1.6.2. Communicate with generators concerning fuel sources.

1.6.3. Request the RC to take specific action.

1.6.4. Identify existing Operating Plan(s) that would be informed by the ERA results should the forecasted energy emergency become an actual emergency.

Likes 0	
Dislikes 0	

Response

LaKenya Vannorman - LaKenya Vannorman On Behalf of: Chris Gowder, Florida Municipal Power Agency, 5, 6, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 6, 3; Navid Nowakhtar, Florida Municipal Power Agency, 5, 6, 3; - LaKenya Vannorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	
Comment	
FMPA supports and recommends implementation of Southern Company comments.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	No
Document Name	
Comment	
SRP agrees and supports comments from Tacoma Power.	
Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	
Comment	

AZPS feels the set of scenarios being proposed should be considerations and not mandatory Requirements. AZPS agrees with EEI's comments that the Balancing Authority should be able to determine and develop scenarios appropriate for their specific area. AZPS also agrees with the following EEI comments:

While EEI agrees that ERAs should be performed using scenarios and contingencies that are likely to occur or have a history of occurring, we do not agree that the scenarios in requirement R2 are the correct level of risk within the Operations Planning Horizon nor that the scenarios are clear and understandable. We suggest that the SDT consider incorporating scenario development within Requirement R1.

We also do support the proposed number and prescription in BAL-007-1 for the scenarios, noting the statement on page 4 of the SAR, "*For energy reliability assessments, measurements and observations should be compared to predefined criteria, and results should be in terms of impact on the BES. The predefined criteria do not need to be specifically defined within the Standard. Instead, each entity will establish and document criteria as part of complying with the Standard*." While we support that the scenarios should contain contingencies related to demand, energy, and fuel considerations;

the BA should be afforded the latitude to determine what is reasonable to include within the Operations Time Horizon. The BA should also not be required to include high-risk, low-probability scenarios in their ERAs.

We are also concerned that as written this requirement would require more BA resources in order to create the large number of studies being proposed and question whether these studies would provide the desired reliability benefit. Moreover, requiring a specific number and type of scenarios to be analyzed in each time-step of the ERA process could result excessive amounts of data that could produce “false positives” that would make it difficult to determine when the BA should act.

We further question the usefulness of the Attachment 1 and the identified contingencies because it is unclear whether they add any reliability benefits or provide any utility in developing useful ERAs. The energy contingency in Attachment 1 also appears to be redundant to the Most Severe Single Contingency (MSSC) calculation already required in BAL-002 which is used to determine a Balancing Authority’s Contingency Reserves. It is also important to recognize that the fuel contingency in Attachment 1 would only be as useful as the Balancing Authority’s visibility into fuel supply information. We agree that the BA should determine the energy and fuel contingencies that would yield the most value from the ERA process for their geographic region and market structure but see little value in what is provided in Attachment 1. For this reason, we ask the SDT to consider removing Attachment 1 from this standard.

Finally, the R3 requirement to develop Operating Plan(s) to *minimize* unacceptable risk identified in the ERA needs to be addressed along with ERA scenarios. The SDT made it clear that these Operating Plans should be specific to the new BAL-007 standard and would not overlap or conflict with existing Operating Plan(s) already required in TOP-002-4 R4 Next Day, BAL-002 R2 MSSC Contingency Reserves, and EOP-011-2 R2 Energy and Capacity Emergencies. However, this standard does not provide the BA with any authority to *minimize* forecasted energy emergencies. This limits the actions a BA can take in BAL-007 to increased study frequency, communication with generators and other relevant entities, requesting that the RC take action such as moving generation outages, or identifying existing Operating Plans that would be enacted should the risk of an actual energy emergency become imminent. With this in mind, we suggest that the SDT consider reducing the scope of requirement R3 and making it a sub requirement of R1. We additionally ask the SDT to consider changing the requirement to the development of strategic actions that would minimize the risks associated with energy emergencies that the BA could reasonably take up to and including the identification of existing Operating Plans, should a forecasted energy emergency become an actual energy emergency.

To address these concerns, we offer the following changes to Requirements R1, R2 and R3 for SDT consideration (changes in boldface):

R1.

1.4. Include a documented set of Balancing Authority determined ERA scenarios to be considered that include the following:

1.4.1. The Projected System Load

1.4.2. Energy and/or Fuel contingencies

1.4.3. Any event that is projected or likely to occur.

1.4.4. How these contingencies are considered.

1.5 Include a documented rationale for scenarios chosen in Requirement R1.4

1.6 Develop and document mitigating actions that could be used to *minimize* risk(s) identified by the results of an ERA. Such actions may include but are not limited to:

1.6.1. Increase ERA study frequency.

1.6.2. Communicate with generators concerning fuel sources.

1.6.3. Request the RC to take specific action.

1.6.4. Identify existing Operating Plan(s) that would be informed by the ERA results should the forecasted energy emergency become an actual emergency.

In R1.6, the SDT should consider removing "unacceptable" as it may perceived differently by the entity.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen	
Answer	No
Document Name	
Comment	
ISO-NE believes the listed scenarios are sufficient, however there should be some allowance and flexibility for BAs to determine if certain scenarios are not applicable to their area or if additional scenarios are needed.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
BAs across the NERC footprint have large variations in size, risks faced, and operational characteristics. The scenarios specified in the Requirement R2 do not capture the correct level of risk for all BAs, and it is doubtful whether any prescribed set of scenarios would function equally well for all BAs. A better approach would be to allow each BA to develop its own scenarios that best capture the specific risks of its unique BA Area. In addition, the references to fuel contingencies are very expansive and appear to require BAs to evaluate portions of the supply chain that they have no authority over and for which they cannot obtain meaningful data, such as uranium supply chains, gas pipeline design and operations, and railroad networks used for shipping coal. Finally, the term "likely" in Requirement R2.1.7 is ambiguous; replacing it with the term "credible" would result in a less ambiguous Requirement.	
Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 6	
Answer	No

Document Name	
Comment	

The scenarios to be considered are reminiscent and duplicative of those already prescribed under existing standards (EOP-011 and TOP-002, Requirement R8) and should not be prescribed in BAL-007. Instead, the BA should have the ability to determine the scenarios relevant to ensuring reliable operations in its footprint.

Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	No
Document Name	
Comment	

IID believes the proposed scenarios for ERA levels appear to be reasonable. Due to the inherent complexity and uncertainty of forecasting the weather and allocating water supplies during scarcity, IID believes that evaluating “water as fuel” for hydro generation should be limited to situations where hydro generation makes up a significant portion of the BA’s generation mix.

Likes 0	
Dislikes 0	
Response	

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	

Southern Company supports the EEI comments and agrees that the BA should determine the number of scenarios, scenario components, and Energy and Fuel Contingencies that are reasonable to include in an ERA for their area or market. Southern also agrees with EEI that the BA does not have additional authority to mitigate forecasted energy emergencies and any actions taken would be to minimize risk.

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

It is our opinion that specific scenarios should not be included in the Reliability Standard. We believe that by doing so, it makes the Reliability Standard too prescripve and limits the ability of the BA to appropriately develop specific scenarios for their Balancing Authority Area and the unique challenges encountered therein.

Likes 0	
Dislikes 0	

Response

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee

Answer	No
Document Name	

Comment

The IRC SRC has two points we would like addressed to this question.

1) BA determination and responsibility over ERA scenarios.

2) Relocation and revision of Fuel Contingency requirement to the Technical Rationale and to include only readily available information to BAs.

Requirement 2:

To accommodate alternative ERA approaches, the SRC proposes that the **BA should have the ability to determine the ERA scenarios relevant to ensuring reliable operations in its footprint**. Examples could still be provided in the Technical Rationale.

As we move into the future, and probabilistic models and analysis become more prevalent, the standard should be flexible enough to allow for industry and technology changes to reflect generally accepted industry practices.

As noted above, the SRC recommends that the BA have the ability to determine the ERA scenarios relevant to ensuring reliable operations in its footprint. Therefore, the contingencies outlined in **Attachment 1 should be migrated to the Technical Rationale.**

The SRC requests the following change under Fuel contingency:

Current: The fuel sources to be considered should include pipelines, suppliers of consumable fuels, and variable sources like solar and wind energy.

Proposed Revision: The fuel sources to be considered should include information readily available to the BA at the time of the ERA (or as provided to the BA by the Generator Operator) and may include pipelines, suppliers of consumable fuels, and variable sources like solar and wind energy.

Likes 0	
Dislikes 0	
Response	
Holly Mitchell - NorthWestern Energy - NA - Not Applicable - WECC	
Answer	No
Document Name	
Comment	
R2 specifies “an” energy/fuel supply contingency, implying all known energy/fuel supply contingencies. Attachment 1 explicitly defines what “the largest” energy/fuel supply contingency is. It is unclear whether the intention is that only the largest energy/fuel supply contingency is studied or if all known energy/fuel supply contingencies are studied. (This is made clear in the technical justification but is not clear in the text of the standard draft.)	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Darcy O'Connell - California ISO - 2	
Answer	No
Document Name	
Comment	
In addition to supporting comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee, CAISO has the following comments: • Propose the SDT to include language that will allow BAs to exclude unlikely and extreme (improbable) risks from the ERA scenarios	

Likes 0	
Dislikes 0	
Response	
Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	No
Document Name	
Comment	
Chelan PUD recommends that the ERA requirements apply to LSEs and/or LREs and not be assigned to the BA.	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
C. A. Campbell - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	
Entities may have their own resource sufficiency/resource adequacy programs or requirements that entail similar evaluations for upcoming time periods such as peak seasons or situations such as loss of fuel. However, there may or may not be existing requirements to run analysis over a broad spectrum of scenarios even for non-peak months or seasons. Running and retaining the studies and the various scenarios on the timelines listed in the draft standard could take significant resources and time. This effort may be somewhat duplicative of other NERC standards or resource adequacy efforts. NERC should consider whether this requirement and standards are necessary given those other efforts, especially in anticipated system normal conditions.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
BPA recommends that the ERA requirements apply to LSEs and/or LREs and not be assigned to the BA. Both the energy contingency and fuel supply contingency definitions in Attachment 1 suggest information that a BA may not have, and the responsibility for such should belong to a different registered function. For the RTO/ISO regions or those operating under a market structure, the information is submitted by GO/GOPs to the market operator. For regions like BPA, there is no market structure except the Western Energy Imbalance Market, which does not delve into this level of	

requirements. It is within-hour energy transactions between the parties. Many of these RTOs/ISOs also perform the function of RC beside the market function.	
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	

4. The SDT proposes entities determine energy reserve margins which would provide clear criterions for whether or not the results of an ERA require Operating Plan(s) to mitigate potential energy deficiencies. Are energy reserve margins the right method to set that criterion and are the specific energy reserve margin specified in Requirement 8 the correct thresholds for both near-term and seasonal ERAs? Is this approach clear and understandable? If not, please provide the basis that supports your answer or suggestions for revision.

Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	No
Document Name	
Comment	

Chelan PUD is concerned that the requirements of BAL-007 are largely duplicative and potentially inconsistent with established and NERC-approved reserve sharing and FERC approved resource adequacy programs. **BAL-007 must recognize that a regional reliability program is an acceptable way to meet the Standard and thus should be recognized in the Requirement as an acceptable means of meeting the energy reserve margins.**

The Western Power Pool (WPP) is working in conjunction with western utilities to develop the FERC-approved Western Resource Adequacy Program (WRAP). This program takes advantage of load and generation diversity within the western interconnection to provide an efficient and effective program that pools capacity resources together to meet regional resource adequacy requirements without an undue burden on individual Balancing Authorities.

As permitted by NERC and WECC standards BAL-002 and BAL-002-WECC; participating Balancing Authorities within the WPP have instituted the WPP Reserve Sharing Program for Contingency Reserve. By collectively pooling resources, Participants are entitled to use not only their own “internal” reserve resources, but to call on other Participants for assistance if internal reserve does not fully cover a contingency. BAL-007 does not specifically recognize that utilities can meet the requirements dictated by R8 via participation in a regional program such as the WRAP. **This stipulation must be included in the Standard.** By way of comparison, BAL-002 includes language that specifically recognizes the ability to meet reserves via a Reserve Sharing Group. BAL-007 should include similar language to BAL-002 but with a focus on a resource adequacy program participation.

Likes 0	
Dislikes 0	
Response	
Darcy O'Connell - California ISO - 2	
Answer	No
Document Name	
Comment	

In addition to supporting comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee, CAISO has the following comments:

- The CAISO does not support changing the proposed reserve margin unless NERC demonstrates there are technical justification for the change. BAs work with their PUCs to establish reserve margins.

Likes 0	
Dislikes 0	

Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Holly Mitchell - NorthWestern Energy - NA - Not Applicable - WECC	
Answer	No
Document Name	
Comment	

Energy reserve margins are a logical way to set the criterion, although “Energy Reserve Margin” should be a defined term. (See Question 7.)

More clarity should be provided with respect to the “largest N-1 Contingency”:

• Is this analogous to Most Severe Single Contingency?

• Is this contingency considering the capacity or the schedule of the lost energy?

• Is the intention that the largest N-1 Contingency is an energy contingency, a fuel contingency, or the greater of the two? Is this the same for each R8.1, R8.2, R8.3?

• Is the intention that the largest N-1 Contingency is what has been modeled in the ERA scenario in R2.1, or is it effectively an N-1-1 for R8.2 and R8.3 (e.g. for R8.2 the scenarios have an energy contingency built in—would the N-1 Contignency called out in R8.2 then be the next greatest N-1?)

The adders in the energy reserve margin calculations do not make sense. A generating unit or transmission path cannot carry >100% of its capacity, so the energy reserve margin should not account for >100% of the N-1. If it is determined that buffer is needed, it should be built into the load adder and/or scenario development process, or a separate buffer term (per comments on the load adder below).
An alternative option for a buffer would be a percentage of available generating capacity.
The technical justification for the 2%/5% load adder is “to reflect the risk of load forecast error”. This would inherently be captured under the development of designated high load cases. The load adder is redundant with the development of high load cases.
It is unclear why R8.2 and R8.3 have different methods for calculating energy reserve margin. This difference is not accounted for in the technical justification and seems to only convolute the energy reserve margin calculations.

Likes 0	
Dislikes 0	
Response	
C. A. Campbell - LS Power Development, LLC - 5	
Answer	No
Document Name	
Comment	

We agree with the energy margin approach only if generator capabilities are adjusted as we recommend in response to Question #2. If the generator capabilities are not adjusted then the energy reserves may not be deployable when required and result in an energy deficit when the analysis suggests their should be.

Likes 0	
Dislikes 0	
Response	
Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	No
Document Name	
Comment	

There are three main issues we seek the SDT to address to this question.

1) BA and RC collaboration to determine an acceptable level of risk.

2) Clarification of the ultimate goal of the standard; i.e. maintaining energy reserve margin or serving load

3) Clarification of duplication between R8.1 and R 8.2.

Energy Reserve Margins

Although there are generally accepted assessment metrics for capacity assessment, there are no generally accepted energy assessment metrics. In absence of generally accepted energy assessment metrics, the SRC proposes that the BA work with its RC to determine the appropriate Energy Reserve margin for its footprint. The margins proposed in the standard can be unreasonably large and do not allow the flexibility necessary for BAs to factor in the impact of Reserve Sharing Groups that they might be members of.

If the SDT is trying to develop industry accepted energy assessment criteria via this proposed standard, the energy reserve margin needs to be considered in combination with the demand scenarios and contingencies to be assessed (i.e., how severe or stressed the scenarios are, and how much energy margin is required).

Finally, the standard needs to acknowledge that there may be times when the BA's ERA indicates there is insufficient energy to serve all the demand while maintaining its energy reserve margin. During those periods, is it more important for the BA to maintain its energy reserve margin by shedding load or by reducing the energy reserve margin to show it can continue to serve load only by reducing the energy reserve margin? The BA standard should not penalize the BA if there are insufficient resources available to serve the projected load as resource adequacy requirements are not under the BA's jurisdiction.

R8.1, R8.2

The requirements for these two are the same; are they intended to be the same? In R8.2 is the contingency intended to be the second largest contingency (the first was already simulated).

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	

Similar to our response to question 3, It is our opinion that it should be up to the individual BA to determine both sufficient energy reserve margins and the method for determining said margins. We do however believe that there is room in the standard to require the BA to consider the ERA scenarios when developing said margins.

Likes 0	
Dislikes 0	
Response	

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	

Southern Company supports the EEI comments and agrees that the BA should determine and set the reserve margin levels with which to compare against the results on an ERA that would provide the most meaningful information for the BA area.

Likes 0	
Dislikes 0	

Response

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	No
Document Name	

Comment

IID believes that Balancing Authorities should be allowed to include energy obtained from a Reserve Sharing Group (RSG) in the calculation of energy reserve margins.

Likes 0	
Dislikes 0	

Response

Jennifer Neville - Western Area Power Administration - 6

Answer	No
Document Name	

Comment

While determining adequate Energy Reserve Margins is important to ensuring energy reliability, care needs to be taken when discussing reserve margins. As written, requirement R8 and its three sub-parts are very prescriptive and limit flexibility and the Technical Rationale is silent as to how the percentages in Parts 8.1-8.3 were determined. There is not a need for the standard to determine a specific threshold. Rather, the BA should be able to determine an appropriate threshold for their footprint based on their criteria.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

It is unclear how factors such as demand response and block load transfers factor in to the concept of an energy reserve margin, so it is difficult to determine whether energy reserve margins are the correct method to determine whether mitigation of potential deficiencies is required. Regardless of how the energy reserve margin is calculated, the margins specified in Requirement R8 for both near-term and seasonal ERAs are unreasonably large. The margins currently specified in Requirement R8 would frequently result in the ERA showing a potential energy deficiency in scenarios where no energy deficiency actually exists, effectively rendering the ERA ineffective at accomplishing its stated purpose. Also, depending on what risk reduction measures may be required (see ERCOT's response to Question 6), this highly conservative margin could also potentially reduce reliability by leading the BA to take actions in the near-term that might lessen its ability to address an actual energy deficiency further in the future. For example, canceling a generator's maintenance outage to secure its availability in the near term to address an energy reserve margin deficiency identified under an ERA could preclude that generator's availability at a later time when it might actually be needed to serve load. The most effective method of evaluating ERA results will vary from BA to BA, and attempting to dictate a particular method or threshold in a Reliability Standard will compromise the usefulness of the ERA.

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

With regards to R8, "…150% of the largest N-1 Contingency within each Balancing Authority's footprint plus at least 2% of the load forecast…". Is that saying, 150% of your largest N-1 and then 2% of the peak load in the study period, or is it based on historical peak? Assuming it is for the study period, if your peak load was 30,000 MW, you'd carry an additional 600 MW of reserve for your assessment timeline? This statement is tied to the near term assessment, so it's done more frequently. Does that imply that we expected to update and change the reserve requirements for each study? Would it not be easier to have this value be a static number based on peak load or seasonal peak load?

What is the technical rationale for developing the new criteria listed in 8.1 through 8.3?

It seems that the criteria could and probably should be the same as the already existing Energy Emergency Alerts (EEAs) as defined by EOP-011. ISO-NE believes that utilizing an already existing EEA levels would be beneficial to streamline the ERA reserve margins

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS believes that R8 should address or include Reserve Sharing Groups. AZPS is not aware of tools to accomplish the energy reserve margins requirement. Is it the BAs that are setting the Reserve Margin or the Load Serving Entities? AZPS agrees with EEI's comments, to remove R8 subsets and keep R8 requirement. The R8.1 is inconsistent with R2.1.1 and R2.1.4 scenarios; R8.1 requires ERMS for the Largest N-1 contingency however R2.1.1 and R2.1.4 are scenarios for normal operating conditions.

Additionally, AZPS agrees with the following EEI comments:

EEI supports the use of energy reserve margins to address potential energy emergencies, however, those reserve margins should not be specifically identified in BAL-007 but the BA should determine what is needed based on regional experience, modeling data, and realistic capabilities.

R8. Each Balancing Authority shall **develop** energy reserve margins for the ERA scenarios **developed under Requirement R2. A technical rationale supporting reserve margins shall be developed to support energy reserve margins for planned scenarios that are based on regional experience, modeling data and realistic capabilities within the BA's area.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Remove 8.2

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	No
Document Name	

Comment

SRP agrees and supports comments from Tacoma Power. In addition, SRP isn't opposed to computing the reserve margins for the time horizons as described in the draft Standard. However, the minimums prescribed in R8 appear to be excessive for most risks, up to 3 to 4 times our Contingency Reserve requirement. Plus, SRP feels that the requirement is completely unreasonable as 150% is excessive and during times of scarcity. SRP believes the example below has more appropriate margins and are more consistent with the at-risk capacity. A BA is then free to use a higher margin if appropriate for a scenario where there is firmer expectation of widespread inability to deliver natural gas or coal, or for periods of low wind or cloudy days.

The following are some examples of more appropriate minimum reserve margins for your consideration.
2.1.1. Projected system load for the interval being studied with system normal (no contingency) conditions; Near-term ERA margin at least 2% of the load forecast, Seasonal ERA margin at least 5% of the load forecast.
2.1.2. Projected system load for the interval being studied with an energy contingency as described in Attachment 1; ERA margin at least the higher of 100% of the largest N-1 Contingency or Near-term ERA margin at least 2% of the load forecast, Seasonal ERA margin at least 5% of the load forecast.
2.1.3. Projected system load for the interval being studied with fuel supply contingency as described in Attachment 1; ERA margin at least 75% of the at-risk generation capacity.
2.1.4. High load for the interval being studied with system normal (no contingency) conditions; Near-term ERA margin at least 2% of the load forecast, Seasonal ERA margin at least 5% of the load forecast.
2.1.5. High load for the interval being studied with energy contingency as described in Attachment 1; ERA margin at least the higher of 100% of the largest N-1 Contingency or Near-term ERA margin at least 2% of the load forecast, Seasonal ERA margin at least 5% of the load forecast.
2.1.6. High load for the interval being studied with fuel supply contingency as described in Attachment 1; and ERA margin at least 75% of the at-risk generation capacity plus 2% of the load forecast, Seasonal ERA margin at least 5% of the load forecast.
2.1.7. If appropriate for the seasonal time horizon, a scenario(s) with a likely event of occurring within the interval being studied that may include

seasonally appropriate historical events, generation specific fuel or energy contingency scenarios, and weather events that are projected to occur if appropriate for the seasonal time horizon only. ERA margin at least 75% of the at-risk generation capacity plus 2% of the load forecast, Seasonal ERA margin at least 5% of the load forecast.

Likes 0	
Dislikes 0	

Response

LaKenya Vannorman - LaKenya Vannorman On Behalf of: Chris Gowder, Florida Municipal Power Agency, 5, 6, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 6, 3; Navid Nowakhtar, Florida Municipal Power Agency, 5, 6, 3; - LaKenya Vannorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

FMPA supports and recommends implementation of Southern Company comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI supports the use of energy reserve margins to address potential energy emergencies, however, those reserve margins should not be specifically identified in BAL-007 but the BA should determine what is needed based on regional experience, modeling data, and realistic capabilities. To address these concerns, we offer the following changes to Requirements R8, including the deletion of subparts 8.1, 8.2 and 8.3 for SDT consideration (changes in boldface):

R8. Each Balancing Authority shall **develop** energy reserve margins for **the** ERA scenarios **developed under Requirement R2. A technical rationale supporting reserve margins shall be developed to support energy reserve margins for planned scenarios that are based on regional experience, modeling data and realistic capabilities within the BA's area.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1	
Answer	No
Document Name	
Comment	
See Tacoma Power comments.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy is concerned that the requirements of BAL-007 are largely duplicative and potentially inconsistent with established and NERC-approved reserve sharing and FERC approved resource adequacy programs. **BAL-007 must recognize that a regional reliability program is an acceptable way to meet the Standard and thus should be recognized in the Requirement as an acceptable means of meeting the energy reserve margins.**

The Western Power Pool (WPP) is working in conjunction with western utilities to develop the FERC-approved Western Resource Adequacy Program (WRAP). This program takes advantage of load and generation diversity within the western interconnection to provide an efficient and effective program that pools capacity resources together to meet regional resource adequacy requirements without an undue burden on individual Balancing Authorities.

As permitted by NERC and WECC standards BAL-002 and BAL-002-WECC; participating Balancing Authorities within the WPP have instituted the WPP Reserve Sharing Program for Contingency Reserve. By collectively pooling resources, Participants are entitled to use not only their own “internal” reserve resources, but to call on other Participants for assistance if internal reserve does not fully cover a contingency. BAL-007 does not specifically recognize that utilities can meet the requirements dictated by R8 via participation in a regional program such as the WRAP. **This stipulation must be included in the Standard.** By way of comparison, BAL-002 includes language that specifically recognizes the ability to meet reserves via a Reserve Sharing Group. BAL-007 should include similar language to BAL-002 but with a focus on a resource adequacy program participation.

Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No

Document Name	
Comment	

See comments submitted by the Edison Electric Institute

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	

R8.1, R8.2

The requirements for these two are the same; are they intended to be the same? In R8.2 is the contingency intended to be the second largest contingency (the first was already simulated).

Energy Reserve Margins

Although there are generally accepted assessment metrics and criteria for capacity assessment, there are no generally accepted energy assessment criteria. In absence of generally accepted energy assessment metrics and criteria, we propose that the BA with the RC determine the appropriate energy measures for its Area.

Since ERA concepts are evolving, developing industry accepted energy assessment criteria will take some time (i.e., what is the appropriate level of energy reserve margins, in combination with the demand scenarios and contingencies to be assessed). The metrics could be included in future when there is industry consensus.

Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3

Answer	No
Document Name	
Comment	

EEI supports the use of energy reserve margins to address potential energy emergencies, however, those reserve margins should not be specifically identified in BAL-007 but the BA should determine what is needed based on regional experience, modeling data, and realistic capabilities. To address these concerns, we offer the following changes to Requirements R8, including the deletion of subparts 8.1, 8.2 and 8.3 for SDT consideration (changes in boldface):

R8. Each Balancing Authority shall **develop** energy reserve margins for **the** ERA scenarios **developed under Requirement R2. A technical rationale supporting reserve margins shall be developed to support energy reserve margins for planned scenarios that are based on regional experience, modeling data and realistic capabilities within the BA's area.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

REMOVE THIS {C}**8.1 For the ERA scenarios identified in Requirement R2.1.1 and Requirement R2.1.4, the energy reserve margin is at least 150% of the largest N-1 Contingency within BAL-007-1 – Energy Reliability Assessments Draft 1 of BAL-007-1 January 2024 Page 7 of 16 Public Public each Balancing Authority's footprint plus at least 2% of the load forecast for the near-term ERA or at least 5% of the load forecast for the seasonal ERA;**

REMOVE THIS {C}**8.2 For the ERA scenarios identified in Requirement R2.1.2 and Requirement R2.1.5, the energy reserve margin is at least the larger of 150% of the largest N-1 Contingency within each Balancing Authority's footprint or 2% of the load forecast for the near-term ERA or at least 5% of the load forecast for the seasonal ERA; and**

REMOVE THIS {C}**8.3 For the ERA scenarios identified in Requirements R2.1.3, Requirement R2.1.6, and Requirement R2.1.7, the energy reserve margin is at least 125% of the largest N-1 Contingency within each Balancing Authority's footprint.**

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	

EEI supports the use of energy reserve margins to address potential energy emergencies, however, those reserve margins should not be specifically identified in BAL-007 but the BA should determine what is needed based on regional experience, modeling data, and realistic capabilities. To address these concerns, we offer the following changes to Requirements R8, including the deletion of subparts 8.1, 8.2 and 8.3 for SDT consideration (changes in boldface):

R8. Each Balancing Authority shall **determine develop** energy reserve margins **calculated** for **each time step of an the** ERA scenarios **developed under Requirement R2. A technical rationale supporting reserve margins shall be developed to support energy reserve margins for planned**

scenarios that are based on regional experience, modeling data and realistic capabilities within the BA's area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

{C}**8.1 For the ERA scenarios identified in Requirement R2.1.1 and Requirement R2.1.4, the energy reserve margin is at least 150% of the largest N-1 Contingency within BAL-007-1 – Energy Reliability Assessments Draft 1 of BAL-007-1 January 2024 Page 7 of 16 Public Public each Balancing Authority's footprint plus at least 2% of the load forecast for the near-term ERA or at least 5% of the load forecast for the seasonal ERA;**

{C}**8.2 For the ERA scenarios identified in Requirement R2.1.2 and Requirement R2.1.5, the energy reserve margin is at least the larger of 150% of the largest N-1 Contingency within each Balancing Authority's footprint or 2% of the load forecast for the near-term ERA or at least 5% of the load forecast for the seasonal ERA; and**

{C}**8.3 For the ERA scenarios identified in Requirements R2.1.3, Requirement R2.1.6, and Requirement R2.1.7, the energy reserve margin is at least 125% of the largest N-1 Contingency within each Balancing Authority's footprint.**

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

SMUD and BANC support the comments submitted by Tacoma Power.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	No
Document Name	

Comment

R8.1, R8.2

The requirements for these two are the same; are they intended to be the same? In R8.2 is the contingency intended to be the second largest contingency (the first was already simulated).

Energy Reserve Margins

Although there are generally accepted assessment metrics and criteria for capacity assessment, there are no generally accepted energy assessment criteria. In absence of generally accepted energy assessment metrics and criteria, we propose that the BA with the RC determine the appropriate energy measures for its Area.

Since ERA concepts are evolving, developing industry accepted energy assessment criteria will take some time (i.e., what is the appropriate level of energy reserve margins, in combination with the demand scenarios and contingencies to be assessed). The metrics could be included in future when there is industry consensus.

R9: is implicit and superfluous.

R10: In our interpretation, when the BA does the analysis in R1 and R2, if he sees a problem (R3) he will correct it at the source (by applying the management means at his disposal) so that in real time these issues are already addressed. These notifications are therefore unnecessary.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has a concern about the energy reserve margins being the right method to set that criterion. From our perspective, there are generally accepted assessment metrics for capacity assessment, however, there are no generally accepted energy assessment metrics. In the absence of generally accepted energy assessment metrics, there is the concern of the assessment will not meet its expectations.

SPP recommends that the BA work with its RC to determine the appropriate Energy Reserve margin for its footprint. The margins proposed in the standard can be unreasonably large and do not allow the flexibility necessary for BAs to factor in the impact of Reserve Sharing Groups that's associated with their stakeholder process.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments: "R8.1, R8.2 The requirements for these two are the same; are they intended to be the same? In R8.2 is the contingency intended to be the second largest contingency (the first was already simulated). Energy Reserve Margins Although there are generally accepted assessment metrics and criteria for capacity assessment, there are no generally accepted energy assessment criteria. In absence of generally accepted energy assessment metrics and criteria, we propose that the BA with the RC determine the appropriate energy measures for its Area. Since ERA concepts are evolving, developing industry accepted energy assessment criteria will take some time (i.e., what is the appropriate level of energy reserve margins, in combination with the demand scenarios and contingencies to be assessed). The metrics could be included in future when there is industry consensus."	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 5, 3; Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye supports the comments made by ACES: Similar to our response to question 3, It is our opinion that it should be up to the individual BA to determine both sufficient energy reserve margins and the method for determining said margins. We do however believe that there is room in the standard to require the BA to consider the ERA scenarios when developing said margins.	
Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the MRO NSRF for question #4.	
Likes 0	
Dislikes 0	
Response	
Dania Colon - Orlando Utilities Commission - 5	
Answer	No
Document Name	
Comment	
While the FRCC RC does agree that it is good practice to maintain an appropriate level of reserves, we do not agree with the method proposed in this standard. Again, the standard does not allow for multiple BAs to participate in an RSG. The term “Energy Reserve” is not a NERC defined term and seems to be different from “Contingency Reserve” but is not defined or explained in the standard. Existing BAL-002 R2 covers the requirement to maintain a Contingency Reserves equal to, or greater than the MSSC to maintain system reliability. BAL-002 allows for RSGs, while this proposed standard does not. The additional “Energy Reserve” requirements far exceed the existing BAL-002 R2 requirements without an obvious reliability improvement. The requirement for each BA to calculate an energy reserve margin of at least 150% of the largest N-1 Contingency (which now in Attachment 1 requires pipeline contingencies incorporating loss of multiple gasfired generators) within each BA’s footprint plus at least 2% of the load forecast for the near-term ERA or at least 5% of the load forecast for the seasonal ERA is excessive. It would also be excessive for an RSG. FRCC RC does not believe this requirement is needed because Contingency Reserves are already calculated based on the existing BAL-002 R2 standard requirement.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

R8.1, R8.2

The requirements for these two are the same; are they intended to be the same? In R8.2 is the contingency intended to be the second largest contingency (the first was already simulated).

Energy Reserve Margins

Although there are generally accepted assessment metrics and criteria for capacity assessment, there are no generally accepted energy assessment criteria. In absence of generally accepted energy assessment metrics and criteria, we propose that the BA with the RC determine the appropriate energy measures for its Area.

Since ERA concepts are evolving, developing industry accepted energy assessment criteria will take some time (i.e., what is the appropriate level of energy reserve margins, in combination with the demand scenarios and contingencies to be assessed). The metrics could be included in future when there is industry consensus. The SDT may want to consider a working group to further develop this.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

Florida Power & Light does not agree with the methodology proposed in this standard to check the results of an ERA against an “Energy Reserve” margin. The term “Energy Reserve” is not a NERC defined term nor is it defined or well explained in the standard. It is a new term that is different from the NERC defined term “Reserve Margin” or “Contingency Reserve”. Reserve margins already exist sufficient to determine if the results of an ERA would potentially lead to an EEA. The existing BAL-002 R2 standard requirement calculates Contingency Reserves based on the Most Severe Single Contingency (MSSC). Additionally, EOP-011-2 Energy Emergency Alerts already describes the situations when to declare an EEA and uses Contingency Reserves as a measure to determine EEA levels. Requiring the BA to calculate another reserve margin solely for use in the ERA process does not bring added reliability benefit and is redundant.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren agrees with and supports MISO's 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; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power is concerned that the requirements of BAL-007 are largely duplicative and potentially inconsistent with established and NERC-approved reserve sharing and FERC approved resource adequacy programs. **BAL-007 must recognize that a regional reliability program is an acceptable way to meet the Standard and thus should be recognized in the Requirement as an acceptable means of meeting the energy reserve margins.** The Western Power Pool (WPP) is working in conjunction with western utilities to develop the FERC-approved Western Resource Adequacy Program (WRAP). This program takes advantage of load and generation diversity within the western interconnection to provide an efficient and effective program that pools capacity resources together to meet regional resource adequacy requirements without an undue burden on individual Balancing Authorities. As permitted by NERC and WECC standards BAL-002 and BAL-002-WECC; participating Balancing Authorities within the WPP have instituted the WPP Reserve Sharing Program for Contingency Reserve. By collectively pooling resources, Participants are entitled to use not only their own “internal” reserve resources, but to call on other Participants for assistance if internal reserve does not fully cover a contingency. BAL-007 does not specifically recognize that utilities can meet the requirements dictated by R8 via participation in a regional program such as the WRAP. **This stipulation must be included in the Standard.** By way of comparison, BAL-002 includes language that specifically recognizes the ability to meet reserves via a Reserve Sharing Group. BAL-007 should include similar language to BAL-002 but with a focus on a resource adequacy program participation.	
Likes 2	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia; American Municipal Power, 5, Ritts Amy
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

As stated in previous comments in this document, BPA believes BAs are not responsible for this type of energy reserve margin. These requirements are better suited to be performed by LSEs and/or LREs.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

The energy reserve margin criteria in Requirement R8 are very prescriptive and do not appear have an associated technical justification to substantiate the proposed per cent margins and an impact assessment to current operational practices and requirements (for instance, BAL-002 already sets reserves requirements).

BC Hydro suggests that the Standard require the entities to have a documented methodology to determine energy reserve margins based on their prevailing conditions and operational experience.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	

Comment

EEI supports the use of energy reserve margins to address potential energy emergencies, however, those reserve margins should not be specifically identified in BAL-007 but the BA should determine what is needed based on regional experience, modeling data, and realistic capabilities.

Additionally, PNM is concerned that the proposed standard is potentially inconsistent with NERC-approved reserve sharing groups and FERC approved regional resource adequacy programs. Ball-007 should clearly state that participation in these approved programs are acceptable ways to meet the standard. For example, language in BAL-002 specifically recognizes the ability to meet reserves through a Reserve Sharing Group. BAL-007 should make the same clear for regional resource adequacy programs.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1

Answer	No
Document Name	

Comment

Manitoba Hydro is supportive of comments provided by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

“See comments submitted by the Edison Electric Institute”

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment	
Duke Energy supports and recommends implementation of Southern Company comments. Additionally, the energy reserve margin proposed provides a metric for the evaluation and determination of the potential for energy deficiencies. Increasing the proposed margin above 150% risks the creation of 'false positives' for an energy deficiency that isn't plausible.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
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 supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

The requirement to increase reserve margins to 150% of the largest N-1 Contingency within a BA is excessive given the fact that many entities are part of a reserve sharing pool and have access to reserves. The requirement should be flexible, perhaps up to the entity to determine or set on a regional basis, or should be specified to only apply to those not participating in a reserve sharing pool.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	No
Document Name	

Comment

R8.1, R8.2

The requirements for these two are the same; are they intended to be the same? In R8.2 is the contingency intended to be the second largest contingency (the first was already simulated).

Energy Reserve Margins

Although there are generally accepted assessment metrics and criteria for capacity assessment, there are no generally accepted energy assessment criteria. In absence of generally accepted energy assessment metrics and criteria, we propose that the BA with the RC determine the appropriate energy measures for its Area.

Since ERA concepts are evolving, developing industry accepted energy assessment criteria will take some time (i.e., what is the appropriate level of energy reserve margins, in combination with the demand scenarios and contingencies to be assessed). The metrics could be included in future when there is industry consensus.

R9: is implicit and superfluous.

R10: In our interpretation, when the BA does the analysis in R1 and R2, if he sees a problem (R3) he will correct it at the source (by applying the management means at his disposal) so that in real time these issues are already addressed. These notifications are therefore unnecessary.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

While the MRO NSRF acknowledges energy reserve margin may be an important criterion to consider in ensuring energy reliability, the MRO NSRF has several concerns with what is proposed. The MRO NSRF asks the SDT to:

1. Distinguish how BAL-007 differs from BAL-002 and requirements to meet the Most Severe Single Contingency (MSSC) to eliminate opportunities for double jeopardy.

2. Meet with the NERC Resources Subcommittee to garner feedback and recommendations prior to its next posting.

3. Eliminate prescribed energy reserve margin percentages from the standard. Allow each BA to determine their own criteria. Relevant citations from page 4 of the SAR:

a. “For energy reliability assessments, …results should be in terms of impact on the BES.”

b. “The predefined criteria do not need to be specifically defined within the Standard. Alternatively, the standard would require each entity to establish and document criteria as part of complying with the Standard.”

4. Justify how the percentages in Parts 8.1 - 8.3 were determined.

Each BA should be able to determine an appropriate energy reserve margin threshold for their footprint based on their criteria as illustrated by a working example below. With increasing uncertainties in the transitioning fleet and more extreme weather, reliability challenges can arise from more sources than fuel supply alone, including wind, solar, interchanges, etc. than just the largest contingency or load error threat envisioned in Requirement 8. In addition, with the advance of data analytics, some BAs are making progress to quantify “Net Uncertainties” to set the threshold and BAL-007 should not over-prescribe and limit BAs’ good initiatives to best quantify “Net Uncertainty” and inform Operation Planning.

Example: One BA sets its reserve margin threshold based on quantified Net Uncertainties and predicted daily risk profiles. The Net Uncertainty is quantified based on the historical distribution at specified confidence levels, accounting for load, wind and solar forecast errors, thermal generation availability and interchange changes between Next-Day projection and Real-Time actual. A machine learning model is used to predict the daily risk profile at High/Medium/Low levels based on what was experienced in historical like-weather and operating conditions.
This dynamic, data-driven method is more reliable and efficient to manage varying system conditions instead of static administrative values which can become stagnant.
The measure should be one of how reliably the BA was able to plan to serve its load.

Likes 0	
Dislikes 0	

Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	

Black Hills Corporation mostly agrees with EEI's comments:

Black Hills believes this requirement may impact BAs differently based on the makeup of their generation resource portfolio and should consider other initiatives being taken by the industry such as WRAP and existing reserve sharing group requirements listed in BAL-002 before unilaterally mandating energy reserve margins for all BA footprints. Additionally, depending on a BAs current generation resource makeup and reserve margins, it could take 2-5 Years for a BA to build generation capacity that allows for compliance with this requirement.

EEI supports the use of energy reserve margins to address potential energy emergencies, however, those reserve margins should not be specifically identified in BAL-007 but the BA should determine what is needed based on regional experience, modeling data, and realistic capabilities.

R8. Each Balancing Authority shall (*remove:* ***determine***) **develop** energy reserve margins (*remove:* ***calculated***) for (remove: ***each time step of an***) **the** ERA scenarios **developed under Requirement R2. A technical rationale supporting reserve margins shall be developed to support energy reserve margins for planned scenarios that are based on regional experience, modeling data and realistic capabilities within the BA's area.** *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

(*remove 8.2:* *8.2 For the ERA scenarios identified in Requirements R2.1.3, Requirement R2.1.6, and Requirement R2.1.7,* ***an*** *energy reserve margin* ***of at least of*** *125%* ***or more should be considered for of*** *the largest N-1 Contingency within each Balancing Authority's footprint.)*

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	No
Document Name	
Comment	

Not for all applicable entities. An energy reserve margin of 150% of a BAs largest N-1 contingency is too high for small BAs or BAs that are part of an RSG. The DT need to address the needs of the small BAs as well as the large ones.

Likes 0	
Dislikes 0	
Response	

Richard Gilbert - Florida Reliability Coordinating Council – Member Services Division - 8 - SERC	
Answer	No
Document Name	
Comment	

While the FRCC RC agrees that it is good practice to maintain an appropriate level of reserves, we do not agree with the method proposed in this standard – a method which is not only new but also does not allow for multiple BAs to participate in an RSG or Collection of BAs.

First, the standard refers to the term "Energy Reserve," which is not a NERC defined term, and fails to provide an explicit definition or clear explanation of what this reserve calculation is or why a new calculation is even necessary. Though the term appears to be used similarly to the "Contingency Reserve" term, there are obvious inconsistencies that warrant explanation, including that the existing BAL-002 R2 already covers the requirement to maintain a Contingency Reserves equal to or greater than the Most Severe Single Contingency (MSSC) to maintain system reliability. Another inconsistency is that BAL-002 allows for RSGs or Collection of BAs, while this proposed standard is entirely silent on the topic of RSGs or Collection of BAs. If the standard intended for the "Energy Reserve" requirements to change, enhance, or exceed the existing BAL-002 R2 "Contingency Reserve" requirements, then it has done so without explanation or any obvious reliability improvement.

FRCC also notes the excessiveness of the standard's requirement for each BA to calculate an energy reserve margin of at least 150% of the largest N-1 Contingency (*which now in Attachment 1 requires pipeline contingencies incorporating loss of multiple gas-fired generators*) within each BA's footprint plus at least 2% of the load forecast for the "Near-Term" ERA or at least 5% of the load forecast for the seasonal ERA. (As explained previously, FRCC objects to the standard' use of the term "Near-Term," as it is not clearly defined.) Not only is this requirement excessive for an individual BA, but it would also be excessive for an RSG or Collection of BAs. Regardless, the requirement is unnecessary because Contingency Reserves are already calculated based on the existing BAL-002 R2 standard requirement. The existing BAL-002 R2 standard requires calculation of Contingency Reserves based on the MSSC and only once per year. The EOP-011-2 Attachment 1 Energy Emergency Alerts describes the circumstances to declare an EEA and uses Contingency Reserves as a measure to determine EEA level. Should the SDT feel the need to include language in this standard to compare the results of ERAs against reserves they should consider comparing ERA results to the reserve requirements in BAL-002 and EOP-011. Requiring the BA to calculate another reserve margin solely for use in the ERA process does not bring added reliability benefit.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

BAL-007 is cited as being part of NERC's resiliency initiative, but it does not deal with the paramount challenge in this respect – resource adequacy, i.e. dwindling reserve margins and a lack of dispatchable generation. This issue requires Corrective Action Plans (CAPs), including making Reliability Must-Run (RMR) designations, to forestall disastrous demand-vs-capacity mismatches.

BAL-007 calls instead for Operating Plans, in accordance with the SAR goal to, "address energy assurance rather than resource adequacy." It is not possible however to have one without the other. Energy supply cannot be ensured if the equipment needed to generate or store it is lacking.

The “general processes” of BAL-007 Operating Plans may be useful for near-term (several days to weeks) ERAs, but actions such as rescheduling outages and conserving fuel can do nothing for a fundamental mismatch of electric power demand and generation/storage capacity. The Technical Rationale of BAL-007 admits as much by including load shedding among the elements that may be included in the Operating Plan.

One cannot plan for only a moderate degree of blackouts. One of the principal lessons of Winter Storm Uri is that extreme weather is associated with extreme uncertainty regarding load predictions, generation plant survival, fuel supplies, ability to draw power from neighboring areas and the like. A planned mere bobble in BES reliability may therefore quickly become a full-scale disaster.

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

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

Answer	
Document Name	

Comment

NA

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE appreciates the SDT's efforts to draft a clear standard for entities to determine energy reserve margins to provide criterions for whether or not the results of an ERA require Operating Plan(s) to mitigate potential energy deficiencies. Texas RE is not quite clear on the difference between "energy reserve margins" and "contingency reserves", which are procured to address forecasting errors or to replace deployed reserves due to system generation tripping or other operational issues.

BAs procure various ancillary service products to meet Primary Frequency Response (PFR), Reg up, contingency reserves, non-spin, etc. some of these products are for load forecast uncertainty, frequency response due to the loss of the largest unit or load variation in real-time. Is the SDT's intention that this energy reserve margin be in addition to the ancillary services procured based on the expected system conditions?

Likes 0	
Dislikes 0	

Response

5. Does the proposed new standard address the reliability gaps or risks identified in the SAR and differentiate itself from other standard requirements? In your response, please provide any information that supports your answer.

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	
Comment	

BAL-007 follows the SAR, but the SAR does not address grid resiliency, as explained above.

Likes 0	
Dislikes 0	
Response	

Richard Gilbert - Florida Reliability Coordinating Council – Member Services Division - 8 - SERC

Answer	No
Document Name	
Comment	

The new standard neither addresses reliability gaps or risks nor differentiates itself in any way, as assessment of the same Bulk Power System risks is already addressed comprehensively in BAL-002-3 (DCS), EOP-011-2 (Emergency Operations), EOP-012-1 (Extreme Cold Weather preparedness and Operations), and TOP-001-5 (Transmission Operations). This standard is largely duplicative of existing standards.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	
Comment	

The proposed standard does not address the following items identified in the SAR.
Page 4: “For energy reliability assessments, … results should be in terms of impact on the BES.”
“The predefined criteria do not need to be specifically defined within the Standard. Alternatively, the standard would require each entity to establish and document criteria as part of complying with the Standard.”
In addition, there is a lack of clarity and significant overlap as to how BAL-007 will work with existing NERC standards: TOP-002, BAL-002 and BAL-003.

Finally, the MRO NSRF supports the coordination of Operating Plans among BAs, if not addressed under BA-BA Coordination Agreements. For example, it would make sense to reconcile assumed energy transfers as part of the ERA, particularly for systems where such transfers are material (see Project 2022-03 SAR page 4: “Energy reliability assessments should be required to be coordinated between areas to synchronize interchange assumptions.”).

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

The proposed standard seems to place a lot of additional study and reporting requirements on entities that are already providing similar information by way of separate resource adequacy programs, operating plans, emergency plans, or NERC standards. NERC should consider alternative programs sufficient.

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 supports the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment	
Duke Energy supports and recommends implementation of FRCC comments.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
Manitoba Hydro is generally supportive of MRO NSRF comments. Manitoba Hydro supports the intent to coordinate Operating Plans among BAs. The Manitoba Hydro system is predominantly hydroelectric and, similar to other hydro dominant systems, is highly interconnected to neighboring BAs, therefore coordination on assumed energy transfers can be an important aspect of seasonal and shorter term operations planning.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	

PNMR supports allowing regions to develop processes tailored to their region and experiences as noted by EEI.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

BPA has internal generation planning processes for evaluating risks to meet its forward load obligations, but these do not cover the entire load and generation of the BA. Determining a consistent metric for load planning would streamline processes for identifying response plans to seasonal extreme events. BPA recommends this standard clarify the responsibilities of actions different Registered Entities (RC, TO/TOP, GO/GOP, {LSE if reinstated}, and BAs) for developing, evaluating, and executing action plans to cover identified risks for extreme seasonal events. Reiterated, BPA does not perform this work as a BA and does not cover all load and generation in the BPA BA.

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; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

The proposed standard addresses the reliability gaps identified in the SAR; however, it does not differentiate itself from other existing standards. There is a lack of clarity and significant overlap as to how BAL-007 will work with existing NERC standards: TOP-002, BAL-002 and BAL-003. The new requirements should be written into an existing standard as a starting point.

In addition, the standard should clearly indicate what reliability benefit will be received from doing the additional work. A small BA will be pulling from the same resources to meet BAL-007 as it currently uses to meet TOP-002, BAL-002 and BAL-003. For example, the additional reliability benefit to collecting 30-days worth of hourly data utilizing the same resources is likely to be counterproductive.

There is a need to balance administrative effort against reliability benefit. The Balancing Authority should have some discretion in determining when to develop a formal written Operating Plan(s) to mitigate energy reliability risks as, the further out an Operating Plan is written, the more times it will need to be modified.

Likes 2	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia; American Municipal Power, 5, Ritts Amy

Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports MISO's comments.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Florida Power & Light does not agree that this proposed standard address's reliability gaps due to its redundancy when compared to existing and enforceable reliability standards e.g., BAL-002, BAL-502, EOP-011, TOP-002 just to reference a few. The results of an ERA can only prompt more frequent analysis, communication to other entities, and informing existing standard requirements already being performed.	
Likes 0	
Dislikes 0	
Response	
Dania Colon - Orlando Utilities Commission - 5	
Answer	No
Document Name	
Comment	
The assessment of energy risks to the Bulk Power System is already addressed in BAL-002-3 (DCS), EOP-011-2 (Emergency Operations), EOP-012-1 (Extreme Cold Weather preparedness and Operations), and TOP-	

001-5 (Transmission Operations). An addition to these standards that further defines and delineates the responsibility for the Energy Risk Assessment would accomplish the same objectives as the new standard.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the MRO NSRF for question #5.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	No
Document Name	

Comment

SPP has a concern about the proposed standard and how it will address any reliability gaps or risks identified.

From our perspective, it is also unclear at what point in the process mitigation plans under the standard would need to be developed, and whether the BA would have discretion in determining when to develop a mitigation plan to mitigate energy reliability risks. Such discretion will be necessary if the mitigation measure requirement is retained, as the further out a mitigation plan is written, the more frequently it will need to be modified as circumstances change.

Although mitigation of threats is important, there may be limited options available, and the effectiveness of a mitigation strategy may be dependent on circumstances beyond the BA's direct control. Therefore, the standard should focus on performing the ERA, identifying potential issues, and collaborating with neighboring BAs to address issues that cross seams. SPP supports and sees value in advance, multi-day operations planning as it increases the amount of time Operations must formulate plans prior to the Operating Day. In terms of mitigation, it will be important to allow the BA to have flexibility, as plans will continue to change along with the weather forecast, load forecast, unplanned outages, generator availability, etc. as the Operating Day approaches.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC support the comments submitted by Tacoma Power.	
Likes 0	
Dislikes 0	
Response	

Aaron Staley - Orlando Utilities Commission - 1	
Answer	No
Document Name	
Comment	
See Tacoma Power comments.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI supports the direction of BAL-007-1, however, we do not agree with the prescriptive language currently contained in this draft. We note that there are significant regional differences regarding the type and appropriate actions necessary to address energy emergencies, therefore BAs should be given the latitude to develop processes that are tailored to their region and experiences.	
Likes 0	

Dislikes 0	

Response

LaKenya Vannorman - LaKenya Vannorman On Behalf of: Chris Gowder, Florida Municipal Power Agency, 5, 6, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 6, 3; Navid Nowakhtar, Florida Municipal Power Agency, 5, 6, 3; - LaKenya Vannorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

FMPA supports and recommends implementation of Southern Company comments.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	No
Document Name	

Comment

SRP agrees and supports comments from Tacoma Power.

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

As stated in a previous response, the Operating Plan submission and review with the RC has created an administrative burden for both the BA and RC with minimal additional reliability benefit. Since Operating Plans are already required under EOP-011 and TOP-002, the administrative requirements of R4-R6 are duplicative and are recommended to be removed.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Due to the issues identified in ERCOT's responses to other questions, the reliability benefit of this standard as drafted is unclear. It is unclear what actions BAs would need to undertake as a result of this standard that they do not already perform, and the standard would require each BA to devote significant time, effort, and resources to performing evaluations that may not yield useful information about its particular BA Area.

Likes 0	
Dislikes 0	

Response

Jennifer Neville - Western Area Power Administration - 6

Answer	No
Document Name	

Comment

The proposed standard addresses the reliability gaps identified in the SAR; however, it does not differentiate itself from other existing standards. There is a lack of clarity and significant overlap as to how BAL-007 will work with existing NERC standards: TOP-002, BAL-002 and BAL-003. The new requirements should be written into an existing standard as a starting point.

In addition, the standard should clearly indicate what reliability benefit will be received from doing the additional work.

Likes 0	
Dislikes 0	

Response

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	No
Document Name	

Comment	
IID believes the proposed standard does not sufficiently differentiate itself from existing standards to warrant the creation of a new standard. There does not appear to be anything significant in the proposed BAL-007-1 that cannot be incorporated into existing TOP, EOP, and TPL standards. For example, TPL-001 already requires that Planning Assessments be conducted for multiple planning horizons. The proposed standard does not provide any guidance for the setting of “predefined criteria”. Because meeting or not meeting “predefined criteria” requires the initiation of Corrective Action Plans, some guidance should be provided by the standard for the creation of those criteria.	
Likes 0	
Dislikes 0	
Response	

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company supports the EEI comments that the standard, as written, does not address the reliability gaps or risks.	
Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee	
Answer	No
Document Name	
Comment	

The IRC SRC seeks responses to four main issues for this question.

1) Accommodating existing and effective processes in place to assess energy risk.

2) BA determination of timing for developing mitigation plans.

3) Shift focus of the standard to performing assessments and having actions ready and less on what is an appropriate level of risk for all regions and entities.

4) Process and requirements for the BA to submit plans to the RC without mandating an extended (60-day) formal review and feedback loop

While the SRC supports the need to address the reliability gaps/risks identified in the SAR, the administrative effort needed to implement a standard must be balanced against the resulting reliability benefit. In this instance, the approach described in the standard may not work for all entities and could require some to replace existing processes that are working well with something that is less effective and more administratively burdensome. This is why the SRC is advocating the need for a less prescriptive approach and added flexibility.

It is also unclear at what point in the process mitigation plans under the standard would need to be developed, and whether the BA would have discretion in determining when to develop a mitigation plan to mitigate energy reliability risks. Such discretion will be necessary if the mitigation measure requirement is retained, as the further out a mitigation plan is written, the more frequently it will need to be modified as circumstances change.

Although mitigation of threats is important, there may be limited options available, and the effectiveness of a mitigation strategy may be dependent on circumstances beyond the BA's direct control. Therefore, the standard should focus on performing the ERA, identifying potential issues and collaborating with neighboring BAs to address issues that cross seams. The SRC supports and sees value in advance, multi-day operations planning as it increases the amount of time Operations has to formulate plans prior to the Operating Day. In terms of mitigation, it will be important to allow the BA to have flexibility, as plans will continue to change along with the weather forecast, load forecast, unplanned outages, generator availability, etc. as the Operating Day approaches.

The SRC proposes that if ERA procedures and mitigation measures are required to be submitted to the RC, the submission process should resemble the process used under TOP-002, which does not require RC review and feedback concerning the BA's next day methodology. TOP-002 also does not require RC review of Operating Plans, which in large part are coordinated with neighboring BAs and submitted to the RC for situational awareness and coordination purposes.

If RC participation in the ERA process is retained, language should be added to the relevant requirements indicating that the submittal of the ERA process to the RC is only required "upon RC request." Pursuant to NERC Standards Efficiency Review (SER) criteria, requirements R4, R5 and R6 should be stricken and modifications to the language in R1 and R2 should remove the requirement that the ERA process be "Reliability Coordinator reviewed."

R1. Each Balancing Authority shall document and maintain an Energy Reliability Assessment (ERA) process, which shall be reviewed at least annually and updated, if necessary.

R2. Each Balancing Authority shall develop, document, and maintain a set of ERA scenarios for both the near-term and seasonal time horizons.

R4. The Balancing Authority shall submit the following information to its Reliability Coordinator for review upon request   : [Violation Risk Factor: Low] [Time Horizon: Operations Planning]

Likes 0	
Dislikes 0	

Response

Darcy O'Connell - California ISO - 2

Answer	No
Document Name	

Comment

In addition to supporting comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee, CAISO has the following comments:

- A reliability that addresses energy is needed in the industry and BAL-007 is a step to address energy sufficiency. The CAISO believes that R2.1.2 is broad enough and gives BAs the ability to model expected variability caused by solar rooftop PV and expected charging patterns for electric vehicles for near term and seasonal and long term assessments.

- Did the SDT considered the counter argument of oversupply conditions if we procured 150% reserves during periods of high renewable penetration? and the risk didn't materialize? It is not clear if this 150% reserve is based on demand or a combination of demand and generation.

Likes 0	
Dislikes 0	

Response

Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD

Answer	No
Document Name	

Comment

Chelan PUD belongs to a regional reliability program and believes that is an acceptable way to meet this standard.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	Yes
Document Name	

Comment

Black Hills Corporation agrees with EEI's comments:

EEI supports the direction of BAL-007-1, however, we do not agree with the prescriptive language currently contained in this draft. We note that there are significant regional differences regarding the type and appropriate actions necessary to address energy emergencies, therefore BAs should be given the latitude to develop processes that are tailored to their region and experiences.

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	
This standard does address a different time frame than other standards. Resolution of natural gas supply issues would be dependent on BA-developed Operating Plans.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 5, 3; Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	

Buckeye supports the comments made by ACES: While we do agree that the proposed Reliability Standard addresses the reliability risks identified in the SAR, we do not fully agree with the currently proposed process for doing so.	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
EEI supports the direction of BAL-007-1, however, we do not agree with the prescriptive language currently contained in this draft. We note that there are significant regional differences regarding the type and appropriate actions necessary to address energy emergencies, therefore BAs should be given the latitude to develop processes that are tailored to their region and experiences.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	Yes
Document Name	
Comment	
EEI supports the direction of BAL-007-1, however, we do not agree with the prescriptive language currently contained in this draft. We note that there are significant regional differences regarding the type and appropriate actions necessary to address energy emergencies, therefore BAs should be given the latitude to develop processes that are tailored to their region and experiences.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	

Answer	Yes
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy supports the direction of BAL-007-1, however, we do not agree with the prescriptive language currently contained in this draft. We note that there are significant regional differences regarding the type and appropriate actions necessary to address energy emergencies, therefore BAs should be given the latitude to develop processes that are tailored to their region and experiences.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
AZPS supports the direction of BAL-007-1, however, does not agree with the overly prescriptive language currently contained in Draft 1. AZPS agrees with the following EEI comments: We note that there are significant regional differences regarding the type and appropriate actions necessary to address energy emergencies, therefore BAs should determine and develop processes that are tailored to their region and experiences.	
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	
While we do agree that the proposed Reliability Standard addresses the reliability risks idenified in the SAR, we do not fully agree with the currently proposed process for doing so.	
Likes 0	
Dislikes 0	
Response	

C. A. Campbell - LS Power Development, LLC - 5	
Answer	Yes
Document Name	
Comment	
The SAR left it to the SDT to "[d]efine a period of time to be studied within operation time horizons that appropriately considers the specific characteristics of the resources in the area being evaluated, including such properties as the logistics involved in the replenishment of fuel and the ability to accurately forecast or assume system conditions." The SAR also required the SDT to consider the "time-coupled restrictions on the availability of fuel" and references natural gas delivery specifically. We believe that the SDT's selection of an analysis more than 5-days from the delivery hour does not capture these "time-coupled restrictions." The technical rationale implies that other reliability standards are adequate to address reliability deficiencies from the delivery hour through day 5. We disagree. Irrespective of the term of natural gas transportation contracts that generators may be parties to, the scheduling cycle for natural gas is a 24-hour gas day. Moreover, most generators procure the commodity daily or over a weekend to match their expected operational profile. We are unsure how the proposed standard would capture these concerns of ensuring intra-hour matching or energy and reserves. Perhaps the team believes that an analysis covering a shorter horizon is either not needed or outside the scope of this project. Regardless, the SAR did not limit the horizon of ERAs to 5 days or more; therefore, we encourage the SDT to answer explicitly in its reply whether it concurs with these concerns, and if these concerns are outside the scope of this project how the SDT recommends closing this reliability gap.	
Likes 0	
Dislikes 0	
Response	

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	

Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Holly Mitchell - NorthWestern Energy - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
There will be concern expressed on the possible overlap with other Standards. WECC believes the SDT needs to be extremely clear in that the Requirements here are to mitigate the risks posed and other similar language in other Standards may not capture the risk in the manner in which the SAR was envisioned.	
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	

6. Is the proposed standard practicable to:
i. Be implementable?
ii. Is the proposed standard auditable?
iii. Able to comply with?
In your response, please provide any information that supports your answer.

Diane E Landry - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name CHPD	
Answer	No
Document Name	
Comment	

As currently written, BAL-007 could not be implemented and would force entities to either build or procure a significant amount of new generating capability or place existing generation in continuous standby. Specifically, the energy reserve margins specified in R8 cannot be applied to small Balancing Authorities that have only a handful of generating resources and a small footprint. Complying with BAL-007 would present a significant and unsustainable burden to a small individual BA.

Additionally, the proposed Standard is not practicable as it precludes other methods, such as the Western Power Pool's WRAP, from consideration. Chelan PUD recommends the SDT revise the Standard to focus on results-based outcomes and provide flexibility to the BA to develop their own ERA procedure and scenarios suited to the needs of their footprint, including a means for working with a resource adequacy group to meet required energy reserve margins.

Likes 0	
Dislikes 0	
Response	

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
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, Group Name ISO/RTO Standards Review Committee	
Answer	No

Document Name	
Comment	

The standard is unclear regarding risk mitigation. Specifically, requirement R3 is unclear regarding what constitutes an unacceptable risk, how likely an event must be before the BA has an obligation to mitigate it, and what degree of mitigation is sufficient to satisfy the standard, given the inherent limitations of the mitigation options available to BAs. As stated in the comment to Q5 we ask the SDT to consider how requirements can be written to place less emphasis on how well the mitigation plan performs post-event. Unlike long term planning studies which allow for longer lead times, the BA has limited capability to adjust to the situation at hand.

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 proposed standard does meet the 3 criteria identified above; however, we believe that it is too prescripve and does not account for alternative methods or processes to mitigate risks to the BES. Furthermore, it is our opinion that by forces the BA to utilize a specific method explicitly defined in the Reliability Standard does not allow enough flexibility for future expansion. For example, as Artificial Intelligence (AI) and machine learning algorithms become more prevalent, the proposed standard, as currently written, would need to be modified to take advantage of these emerging technologies.

Likes 0	
Dislikes 0	
Response	

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	No
Document Name	
Comment	

Southern Company supports the EEI comments.

Likes 0	
Dislikes 0	

Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	No
Document Name	
Comment	
IID believes the above issues should be reviewed and resolved prior to implementing BAL-007-1, assuming the creation of a new standard is warranted.	
Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 6	
Answer	No
Document Name	
Comment	
There may be a role to expand the ability of contingency reserve sharing groups beyond meeting BAL-002 to address longer term energy contingencies (as opposed to BAL-002 and real-time events); e.g. provisions for extended calls of reserve energy, if available and mutually agreed upon, (while still restoring Contingency Reserves within the period required by BAL-002 and RSG protocols)	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
The standard's references to operating plans are ambiguous, as Requirements R3 and R9 do not clearly specify what constitutes an unacceptable risk, how likely an event must be before the BA has an obligation to mitigate it, what degree of mitigation would be sufficient to satisfy the standard, and what sorts of mitigation should be presumed to be available to the BA. It is also unclear how a Regional Entity could address these issues in an audit.	

Requirements R3 and R9 could be understood to require elimination of identified unacceptable risks. However, due to the inherent limitations of the mitigation options available to BAs (BAs cannot require that new generation be constructed, and the timelines contemplated in the standard are too short to construct generation in any event; BAs also have little to no authority over fuel supply chains and generator fuel procurement contracts, and cannot rely too heavily on outage coordination, as generators that are denied sufficient time for planned outages are at an increased risk of experiencing a forced outage), there are many scenarios where the only way a BA could mitigate or eliminate identified risks would be to shed load (or plan to shed load) to bring its energy margins back up above the level specified in Requirement R8, even though the R8 margins are significantly higher than the margins at which a BA would ordinarily shed load. However, shedding load would seem to defeat the presumed energy adequacy purpose that underlies the standard.

Aside from shedding load, it is unclear what risk reduction measures BAs might be able to implement as a result of this standard that they do not already implement in the ordinary course of performing their duties, particularly in a scenario that involves a large severe weather event that spans multiple BA Areas, as all available generation would already be online during such an event.

It is also unclear whether the risk reduction measures discussed in Requirement R3 are intended to be developed in response to the results of an ERA or whether a list of potential risk reduction measures is intended to be developed before the ERA is performed (or whether BAs have the flexibility to choose either approach).

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

AZPS does not agree that the standard as proposed is implementable or auditable in its current form.

AZPS agrees with the following EEI comments: EEI does not agree that the standard as proposed is implementable or auditable in its current form. To address our concerns, we suggest making the proposed changes offered in our comments.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	No
Document Name	

Comment

SRP agrees and supports comments from Tacoma Power. In addition, SRP strongly believes that `the concerns expressed in questions 4 and 7 need to be addressed. In addition, is there a requirement that the Operating Plan(s) need to be followed? The different scenarios are helpful but may not necessarily represent reality. Our thought process is that entities can develop the ERAs but most likely those plans won't be utilized when contingencies are experienced.

Likes 0	
Dislikes 0	

Response

LaKenya Vannorman - LaKenya Vannorman On Behalf of: Chris Gowder, Florida Municipal Power Agency, 5, 6, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 6, 3; Navid Nowakhtar, Florida Municipal Power Agency, 5, 6, 3; - LaKenya Vannorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

FMPA supports and recommends implementation of Southern Company comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI does not agree that the standard as proposed is implementable or auditable in its current form. To address our concerns, we suggest making the proposed changes offered in our comments.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1

Answer	No
Document Name	

Comment	
See Tacoma Power comments.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
As currently written, BAL-007 could not be implemented and would force entities to either build or procure a significant amount of new generating capability or place existing generation in continuous standby. Specifically, the energy reserve margins specified in R8 cannot be applied to small Balancing Authorities that have only a handful of generating resources and a small footprint. Complying with BAL-007 would present a significant and unsustainable burden to a small individual BA. Additionally, the proposed Standard is not practicable as it precludes other methods, such as the Western Power Pool's WRAP, from consideration. NV Energy recommends the SDT revise the Standard to focus on results-based outcomes and provide flexibility to the BA to develop their own ERA procedure and scenarios suited to the needs of their footprint, including a means for working with a resource adequacy group to meet required energy reserve margins.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
EEI does not agree that the standard as proposed is implementable or auditable in its current form. To address our concerns, we suggest making the proposed changes offered in our comments.	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
EEI does not agree that the standard as proposed is implementable or auditable in its current form. To address our concerns, we suggest making the proposed changes offered in our 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 and BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC support the comments submitted by Tacoma Power.	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP has a concern that the standard is unclear regarding risk mitigation. Specifically, requirement R3 is unclear regarding what constitutes an unacceptable risk, how likely an event must be before the BA has an obligation to mitigate it, and what degree of mitigation is sufficient to satisfy the standard, given the inherently limitations of the mitigation options available to BAs. Unlike long term planning studies which allow for longer lead times, the BA has limited capability to adjust to the situation at hand.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 5, 3; Jason Procuniar, Buckeye Power, Inc., 4, 5, 3; Kevin Zemanek, Buckeye Power, Inc., 4, 5, 3; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye supports the comments made by ACES: The proposed standard does meet the 3 criteria identified above; however, we believe that it is too prescriptive and does not account for alternative methods or processes to mitigate risks to the BES. Furthermore, it is our opinion that by forces the BA to utilize a specific method explicitly defined in the Reliability Standard does not allow enough flexibility for future expansion. For example, as Artificial Intelligence (AI) and machine learning algorithms become more prevalent, the proposed standard, as currently writen, would need to be modified to take advantage of these emerging technologies.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the MRO NSRF for question #6.	
Likes 0	
Dislikes 0	
Response	
Dania Colon - Orlando Utilities Commission - 5	
Answer	No
Document Name	
Comment	
i. Be implementable? The implementation of this this standard would be hard to accomplish for smaller BAs within the near-term (within 5 years) due to the reserve requirements that is a significant (i.e. 10 times more reserves than before) departure from the current Reliability Guidelines. It would also be difficult for the RCs to increase staffing to allow for the appropriate reviews, responses, collection of compliance evidence, etc. **ii. Is the proposed standard auditable?** The retention of evidence that is necessary to provide adequate compliance with the standard will be a significant impediment to both Balancing Authorities and Reliability Coordinators, for which this type of evidence is already being collected. **iii. Able to comply with?** BAs and RCs would not be able to comply with the current language due to construction restraints and additional personnel requirements.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Florida Power & Light does not agree that the standard is implementable, auditable, or able to be complied with. There are terms within this proposed standard which are undefined and not clearly described thus rendering it difficult to know the correct interpretation of the standard requirements, particularly if BA's had various interpretations of the terms and methods. The proposed standard fails to specify how to mitigate forecasted energy emergencies making it difficult to comply with the requirements to develop mitigation plans in the various studies where forecasted energy emergencies are identified. Additionally, there would be an excessive number of results produced from frequent ERA studies would make auditing difficult. An auditor would have a difficult time reviewing through this volume of analysis to find evidence of compliance or non-compliance.	
Likes 0	

Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports MISO's 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; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
As currently written, BAL-007 could not be implemented and would force entities to either build or procure a significant amount of new generating capability or place existing generation in continuous standby. Specifically, the energy reserve margins specified in R8 cannot be applied to small Balancing Authorities that have only a handful of generating resources and a small footprint. Complying with BAL-007 would present a significant and unsustainable burden to a small individual BA. Additionally, the proposed Standard is not practicable as it precludes other methods, such as the Western Power Pool's WRAP, from consideration. Tacoma Power recommends the SDT revise the Standard to focus on results-based outcomes and provide flexibility to the BA to develop their own ERA procedure and scenarios suited to the needs of their footprint, including a means for working with a resource adequacy group to meet required energy reserve margins.	
Likes 2	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia; American Municipal Power, 5, Ritts Amy
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	

Comment	
Exelon supports the comments submitted by the EEI.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
i. No, BPA believes this is not implementable by a BA. ii. No, as BPA believes this standard would require a BA to acquire information it has no ownership of from other entities. iii. For the reasoning noted throughout our comments, BPA believes a BA could not comply with the proposed standard.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No
Document Name	
Comment	
PNMR supports EEI's response for question 6.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	

Comment	
The use of "Reliability Coordinator-reviewed" language in Requirements R1 and R2 appear to establish a requirement for the RC to review the BA's ERA process and scenarios as part of the BA's compliance, i.e. the BA's process and/or scenarios would be found non-compliant per R1 and/or R2 if the RC hadn't reviewed it. As there are specific Requirements for the BA to submit R1 process and R2 scenarios to the RC in R4, BC Hydro suggests that this is not required and recommends revising R1 wording to remove this language. As drafted, the BAL-007-1 Draft 1 does not seem to account for Reserve Sharing Group based means to alleviating the risks related to resource mix and fuel availability.	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1	
Answer	No
Document Name	
Comment	
MH is supportive of MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"See comments submitted by the Edison Electric Institute"	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No

Document Name	
Comment	
Reference entity comments.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI.	
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 supports the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

The proposed standard places significant additional reporting requirements on BA's where this planning is already taking place under existing programs. As such, the proposed standard would impose burdensome new requirements for little to no benefit. Additionally, some of the requirements (R3 for example) are vague and therefore not practicable to implement. Near-term reliability planning is critical and undertaken today by entities even without this standard. While improvements can always be made, the incremental benefit of the improvement should also be considered. The standard appears to impose broad requirements without recognition of regional or local facts and circumstances. Resources should be focused on addressing high-risk seasons or periods, without requiring significant additional workload in lower-load, lower-risk periods. While events can still happen in those periods, the standard should balance the risk with the additional effort required, particularly given other existing requirements and processes.

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	No
Document Name	

Comment

R1. RF recommends the SDT make wind, solar, and hydro/rain forecasts an explicit category under 1.2.3.

R3. RF notes that "unacceptable risk" has many possible definitions and that "likely to occur" implies probability over 50%, which is a higher bar than normally set for determining BES contingencies that the BA needs to respond to. Better thresholds might be when the ERA has identified a deficiency that could lead to an Energy Emergency Alert, or require implementing capacity emergency procedures in near term planning.

R5 and R6. 60 days may be appropriate for seasonal studies, but RF is concerned it is too long of a review time for the near-term assessments, particularly if new Operating Plans are needed. Additionally, RF notes that M6 references 30 calendar days instead of the R6 60 calendar days requirement. Suggest 24 hours for near term studies.

R10.1 – RF requests the SDT clarify whether "within 24 hours" refers to Operating Plan implementation being required within 24 hours of performing the ERA and comparison, or whether the 24 hours is intended to establish a deadline for the BA to provide results to the RC at least 24 hours before the Operating Plan(s) are required to be implemented. We recommend the 24 hour deadline implementation.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The MRO NSRF does not view the proposed standard as practicable since it precludes other methods that are equally as good and possibly better, from consideration.
Example: One BA sets its reserve margin threshold based on quantified "Net Uncertainties" and predicted daily risk profiles. The "Net Uncertainty" is quantified based on the historical distribution at specified confidence levels, accounting for load, wind and solar forecast errors, thermal generation availability and interchange changes between Next-Day projection and Real-Time actual. A machine learning model is used to predict the daily risk profile at High/Medium/Low levels based on what was experienced in historical like-weather and operating conditions.
This dynamic, data-driven method is more reliable and efficient to manage varying system conditions instead of static administrative values which can become stagnant.
The measure should be one of how reliably the BA was able to plan to serve its load.
The MRO NSRF recommends the SDT revise the standard to focus on results-based outcomes and provide flexibility to the BA to develop their own ERA process and scenarios to meet the reliability needs of its footprint, including a means to working with Reserve Sharing Groups (RSG) to meet desired energy reserve margins.
Contingency reserve sharing groups may be able to develop services beyond those envisioned under BAL-002 to ensure energy adequacy; e.g. provisions for extended calls of reserve energy, if available and mutually agreed upon, (while still restoring Contingency Reserves within the period required by BAL-002 and RSG protocols).

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI's comments:

EEI does not agree that the standard as proposed is implementable or auditable in its current form. To address our concerns, we suggest making the proposed changes offered in our comments.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	No
Document Name	

Comment

Clarity is needed when reviewing auditability with a focus on ensuring the language mitigates the reliability risks. Flexibility is likely to be cited by industry as a consideration, but the SDT needs to consider how much flexibility is needed to ensure reliability. Terms like “unacceptable risk” (Requirement R3) are essentially unauditable. Whatever the entity feels is “unacceptable” and “likely” to occur would be “compliant”. A black out situation for a section of the grid would be considered unacceptable but would the entity consider it likely and create an Operating Plan (which may be covered in other Standards). How would an entity define unacceptable risks?

The timelines suggested in R5 and R6 do not seem to support the ERA scenarios provided or any Operating Plans that may be needed. The near-term ERA timeline will have passed and whatever scenario was developed would have already been completed. Even for the annual ERA process review the timeline may not meet the needs. At a minimum the SDT needs to shorten the timelines for results of the ERA scenarios (and types) to avoid gaps. The timelines, as proposed, produce a reliability gap in terms of ensuring Wide Area reliability. SDT should be aware that anytime a “within X” timeline is provided in a Requirement, that often is the norm to provide information. Considering that near-term is no greater than 6 weeks, multiple near-term scenarios may not be reviewed by the RC. Additionally, the Seasonal periodicity may cause seasonal ERA reviews not to be done in a timely manner.

Likes 0	
Dislikes 0	

Response

Richard Gilbert - Florida Reliability Coordinating Council – Member Services Division - 8 - SERC

Answer	No
Document Name	

Comment

As mentioned throughout FRCC’s comments, several terms within the current language are unclear or undefined, including, without limitation, Near-Term and Energy Reserve. These ambiguities alone would make the standard difficult, if not impossible, to fully implement.

That the standard, as written, fails to address RSGs (or Collection of BAs) in lieu of individual BAs also renders implementation, compliance, and auditing difficult. In the FRCC area, which has an RSG comprised of nine (9) BAs, the RC would be responsible not only to review the ERA processes for each of the nine (9) separate BAs as well as their corresponding near-term and seasonal time horizon scenarios each time they are run, but also to compile all reviews and responses of each individual entity in order to demonstrate compliance for RC function. The tracking of reviews and responses, along with compiling, retaining, and storing evidence, on this individual basis would cause a significant burden on the RC function. Moreover, given the massive amount of evidence collection that would ultimately be required, any auditor would have a Herculean task to parse through and digest the volume of available evidence in order to accurately determine compliance.

The standard's requirements are burdensome to all who play a role in the process -- from generation of multiple ERA results (with six different scenarios per time-step), to the additional calculation of a yet-undefined "Energy Reserve" margin calculation – and would be additionally labor and personnel intensive to perform and capture appropriate compliance evidence. Setting aside the standard's internal ambiguities that would have to be resolved before any entity could even begin to attempt to comply, not only would additional personnel undoubtedly be needed by the RC, but also, the BAs themselves* would not be able to comply without the addition of personnel to assist in performing and analyzing the ERAs, as well as to compile all the required evidence to demonstrate compliance.

* Note that smaller BAs would be disproportionately impacted by the additional "Energy Reserve" margin calculations within the near- term (within 5 years) due to new reserve requirements significantly increasing (i.e. 10 times more reserves than before) from the current BAL-002 standards.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	

Response

Donald Lock - Talen Generation, LLC - 5

Answer	No
Document Name	

Comment

The standard is practical but inadequate, as explained above.

Likes 0	
Dislikes 0	

Response

Holly Mitchell - NorthWestern Energy - NA - Not Applicable - WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

In addition to supporting comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee, CAISO has the following comments:

- Propose to expand the applicability of this standard to entities that potentially need to provide data or assumptions to the BA for development of scenarios and plans. Add applicable entities that will need to provide RC with data and assumptions.
- Propose removing all requirements that are affected by and not currently supported by NERC jurisdiction, like natural gas suppliers, by including this requirements, SDT puts RC and BA entities in a position of making decisions without having complete information. Or a lever to get the information.
- The CAISO believes that each BA would have to tailor the study assumptions (eg through probabilistic production simulations) and recommend their own compliance measures to make this proposed standard implementable. This may cause consistency issues for the RC within multiple BA interconnections.

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	

Is the Standard Implementable? Maybe

Some BAs already have processes that would be compliant with the Standard as written, many others would have to revamp their process to be compliant with it. Does this work for the different size BAs?

Is the Standard Auditable Not sure for all of it. What is the level of mitigation required if a risk is identified. We may identify a risk 3-4 weeks in advance, but where may not be any actions taken until that risk is identified closer to the operating day. This process could potentially require BAs to take actions preemptively when a risk is identified weeks in advance. While not common this could occur where for example an outage was cancelled when it was unnecessary to do so. It would be extremely difficult to write operating plans for every conceivable risk. Able to comply with? Possibly, This question is BA specific. Smaller BAs may not have much trouble. Larger BAs having to coordinate more entities, including gas pipeline information, may have difficulty in retrieving the necessary data to perform the ERAs effectively.

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

7. Provide any additional comments for the SDT to consider, if desired.

Donald Lock - Talen Generation, LLC - 5	
Answer	
Document Name	
Comment	

Composite challenges must also be studied. Winter Storm Uri for example involved an ice storm that took out the wind farms of northern Texas, then low temperature/high wind conditions that froze-up many conventional generation plants and NG production facilities, then a wind drought. A drenching rainstorm the day before the Polar Vortex of 2014 struck soaked insulation at many plants, causing a high number of forced outages, explaining why there were no problems during the nearly-as-cold Polar Vortex of 2015. The fact that these are rare scenarios does not disqualify them from consideration; quite the opposite, these events demonstrate the need to seriously research the weather history.

The, “Fuel supply and inventory concerns,” wording of R1.2.3.2 echoes EOP-011-2 and (soon) EOP-012-2, suggesting that BAs will be dependent on inputs from GOs in this respect. GOs have no knowledge of area-wide limitations of natural gas (NG) production, storage and delivery systems, however. What appears on the surface to be an urgently needed new forecasting element, given the NG disruptions of Winter Storms Uri and Elliott, may therefore yield almost nothing useful for preventing future generation capacity emergencies. Identifying NG constraints would require a major research project by BAs, which BAL-007 fails to require.

The Technical Rational identifies, “arranging for imports from neighboring areas,” as potentially being among the actions triggered by Operating Plans, but BAL-007 should instead prohibit relying on such measures. Recent generation emergencies were caused in large part by lack of concern over generation capacity inadequacies, assuming that one’s neighbors would always have power to spare, only to find that (predictably) adjacent ISOs had the same problems caused by the same storm.

We suggest that the Technical Rationale suggestion (p.9), “If ERA results still indicate unacceptable risk of energy deficiency two days prior to projected event, instruct thermal plants to warm up leading up to event to avoid outages due to ice formations and cold-start issues,” be elevated from a possible element of Operating Plans to a mandatory one. Recent generation capacity emergencies have been badly exacerbated by waiting until the last moment to call-up the reserves, despite the repeated pleas of GO/GOPs over the years that this is the best and least expensive means of enhancing BES reliability during extreme winter weather. Such action is especially needed for combination threats such as the heavy rain-then-deep freeze of the 2014 Polar Vortex.

Likes 0	
Dislikes 0	
Response	

Richard Gilbert - Florida Reliability Coordinating Council – Member Services Division - 8 - SERC	
Answer	
Document Name	
Comment	

FRCC’s position is that the scope of this standard should be revised to reflect the provided comments, including to define all relevant terms, eliminate duplicative and/or confusing language, and allow for the use of RSGs or Collection of BAs. FRCC also urges consideration of the difficulty BAs and RCs would have in reviewing and using the excessive number of results produced from the currently prescribed ERA scenarios.

In addition, from an RC perspective, FRCC has several concerns with the standard that should be considered. First, FRCC maintains that Requirements R5, R6, and R11 would place undue administrative burden on RCs in requiring RCs to compile significant, but unnecessarily excessive volumes of evidence to show compliance of the reviews and timely notifications. FRCC also believes the RC should only be notified when there is an actual reliability issue OR upon request. Any results provided to the RC should indicate an imminent EEA before it is sent to the RC (unless otherwise instructed) to eliminate the excessive number of reviews needing to be performed without improved situational awareness or improved reliability.

Relatedly, the FRCC RC does not agree with the medium violation risk factor associated with Requirement 6. The dissemination of information within 60 days does not elevate to a medium level violation risk factor.

Finally, FRCC would argue that, since the RC must act in accordance with existing standard IRO-001 R1, the additional compliance requirements stated within the standard at issue are unnecessary and that Requirements R10 and R11 should be modified accordingly.

Likes 1	Tallahassee Electric (City of Tallahassee, FL), 1, Langston Scott
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	

Comment

Consider Requirement changes to R1 language as follows to support clarity similar to EOP-011 by using “shall develop, annually maintain, and implement”.   Technical rationale could state that “annually maintain” means annually review and update as needed. Or consider the following: ”Each Balancing Authority shall document, (add "annually review, update as needed"), and maintain a Reliability Coordinator-reviewed Energy Reliability Assessment (ERA) process, (delete "which shall be reviewed at least annually and updated, if necessary"). The ERA process document shall: “. Entities may see the “if necessary” phrase being applied to the review and not necessarily any update. Secondary suggestion would be to add a separate sentence to say “The ERA process shall be reviewed annually, updated as needed based on the review, and provided to the Reliability Coordinator for its review.”

It is not clear how Reserve Sharing Groups may be considered or impacted by this Standard.Should the RSG be included in the applicability section and the appropriate requrements?

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	2022-03_UCF_BAL-007_MRO NSRF_03-05-24_FINAL.docx

Comment

1. Clarify the objective of the standard. What is the goal (metric) we want to achieve? Is it maintaining an energy reserve margin or reliably serving energy needs? In general, the MRO NSRF sees value in a multi-day planning for operational purposes. That said the proposed standard is overly concerned with prescribing how an ERA is performed.

2. The SDT should clarify that ERAs are an assessment. Therefore, if there are insufficient resources in real-time, despite a BA's efforts to effectively plan and execute their plan, there is no compliance exposure to the BA for inability to meet those energy needs. As today, the ERA process should feed into the next day Operating Plans and EOP-011. Load shed is an acceptable tool of last resort in preventing cascading instability and widespread outages.

3. Meet with the NERC Resources Subcommittee (RS) to garner feedback and recommendations prior to the next posting. As the NERC RS is made up of BA subject matter experts, this would be a great committee to run the next version of the draft standard by prior to posting for industry comment. One of the RS's primary responsibilities is to: "Review and assist in the development of interconnection balancing standards to assure problems resulting from balancing do not adversely affect reliability."

4. Expand TOP-002 versus drafting a new standard (e.g. BAL-007). See example below (using TOP-002, R4 as a model):

RX. Each Balancing Authority shall have a multi-day, forward looking Energy Reliability Assessment (ERA) that leads into its next day Operating Plan cited in Requirement R4 that addresses: [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

4.1 Expected generation resource availability, commitment and dispatch

4.2 Expected energy transfers

4.3 Demand patterns

4.4 Capacity and energy reserve requirements, including deliverability capability

4.5 Relevant risk scenarios

4.6 Coordination with neighboring BAs

Consideration should be given to:

• Using the TOP-002 framework. This would eliminate the need to repeat existing requirements; e.g. R4 (entity notification) and R5 (providing a copy to the RC).

• Administrative effort versus reliability benefit. The benefit of ERAs may vary by system. BAs should have discretion as to when an Operating Plan(s) is issued as, the further out an Operating Plan is written, the more times it will need to be modified. Existing TOP-002, R5, provides a backstop as it requires an entity to have an Operating Plan when it reaches next day.

• Using other relevant sources for requirements. For example, FERC-NERC Winter Storm Elliott Report, Recommendation #8 as illustrated below:

o Balancing Authorities should assess whether… a multi-day risk assessment process or advance or multi-day reliability commitments – are needed to address anticipated energy shortages or transmission system-related reliability problems…by performing energy risk assessments…BAs should consider the following:

A. How to account for uncertainty in load forecasts, generating unit fuel availability and extreme weather availability, and the effects of extreme cold weather across multiple regions

B. Committing generating units prior to the onset of extreme weather.

o Bal obtaining fuel), even if no dispatch oc.

5. Eliminate the Reliability Coordinator review of the BA's ERA process envisioned under Requirements R4-R6 as it is largely administrative and offers minimal reliability benefit. Similar to TOP-002 today, RC review of the BA's next day methodology is not required. What is important

is the submittal of Operating Plans to the RC for situational awareness and coordination purposes (see TOP-002, R7).

If retained, add language to indicate the BA is only required to submit their ERA process to the RC "upon request." Pursuant to NERC Standards Efficiency Review (SER) criteria, requirements R4, R5 and R6 should be stricken and the language in R1 and R2 modified to remove "Reliability Coordinator reviewed."

R1. Each Balancing Authority shall document and maintain an Energy Reliability Assessment (ERA) process, which shall be reviewed at least annually and updated, if necessary.

R2. Each Balancing Authority shall develop, document, and maintain a set of ERA scenarios for both the near-term and seasonal time horizons.

R4. The Balancing Authority shall submit the following information to its Reliability Coordinator for review upon request: [Violation Risk Factor: Low] [Time Horizon: Operations Planning]

6. Justify the need to restore seasonal analysis requirements retired pursuant to Project 2014-03 Revisions to TOP and IRO Standards. Project 2014-03 concluded entities already have the ability to determine the timeframe of studies that are needed (see mapping document). As the primary purpose of seasonal studies is to assess planned outage requests, concerns were addressed under IRO-017-1. If there is a reason to perform seasonal studies, the SDT should explain what benefits would be achieved above and beyond those already conducted pursuant to IRO-017 and IRO-008 as detailed below.

Page 36 of the mapping document explains why seasonal studies were retired for Balancing Authorities and Transmission Operators (see excerpts below).

• RETIRE TOP-002-2.1b, R4. Each Balancing Authority and Transmission Operator shall coordinate (where confidentiality agreements allow) its current-day, next-day, and seasonal planning and operations with neighboring Balancing Authorities and Transmission Operators and with its Reliability Coordinator, so that normal Interconnection operation will proceed in an orderly and consistent manner.

• REPLACE with IRO-017-1, R2 and IRO-008-2, R2

o Proposed IRO-017-1, Requirement R2: R2. Each Transmission Operator and Balancing Authority shall perform the functions specified in its Reliability Coordinator's outage coordination process.

o Proposed IRO-008-2, Requirement R2: R2. Each Reliability Coordinator shall have a coordinated Operating Plan(s) for next-day operations to address potential System Operating Limit (SOL) and Interconnection Reliability Operating Limit (IROL) exceedances identified as a result of its

Operational Planning Analysis as performed in Requirement R1 while considering the Operating Plans for the next-day provided by its Transmission Operators and Balancing Authorities.

• JUSTIFICATION Page 41: “Specific requirements for seasonal studies are not necessary as proposed IRO-017-1 allows for the Reliability Coordinator to determine the timeframe of the studies that it needs.”

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	
Document Name	

Comment

Black Hills generally disagrees with BAL-007-1 as currently written and is largely aligned with the edits being submitted by EEI.

The implementation plan/timeline is reasonable as currently written for all requirements with the exception of R8 which could require some BAs to add generation resources to meet compliance with the 150% threshold. Before Black Hills can agree with the implementation timeline there needs to be finalized language within BAL-007-1.

Black Hills Corporation agrees with EEI’s comments: EEI suggests that the term “mitigate” be removed from this Reliability Standard because the BA and RC can only take actions to minimize impacts, they have no ability to modify or correct a resource issue. Please note the suggested changes to the Purpose statement, as well as Requirements R3 and R10 below (in bold face).

Purpose: To assess and (*remove: **mitigate***) **minimize** the risks of energy emergencies in the operations planning time horizon by analyzing the expected resource mix availability and the expected availability of fuel during the study period.

R3. Each Balancing Authority shall develop, maintain, and document one or more Operating Plan(s) to (*remove: **mitigate***) **minimize** unacceptable risk(s) associated with ERA scenario(s) with a likely event of occurring. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R10. Each Balancing Authority shall provide the results of the ERA and the comparison of results from Requirement R9 to its Reliability Coordinator under the following conditions: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

10.1. The ERA comparison to the energy reserve margin requires implementation of an Operating Plan(s) to (*remove: **mitigate***) **minimize the** risks within 24 hours for the near-term time horizon or;

10.2. The ERA performed is a seasonal ERA within 14 calendar days or;

10.3. The Reliability Coordinator has requested the results.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	

DESC does not support draft 1 of BAL-007-1.

Comments:

Dominion Energy recommends the following:

R8:
-Specific examples would be helpful to clarify what is being asked for in these sub-requirements.

R10:
-The time requirements listed are confusing – please clarify with an example and how this pairs with the requirements listed within R8.

Attachment 1

For the first fuel contingency example, how would an entity address this scenario when we do not have historical norms for a contingency like this? Additional clarity would be helpful.

Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	
Document Name	
Comment	

3. Purpose

Availability may be construed to mean Capacity Availability. As such, we propose the following revision:

"To assess and mitigate the risks of energy emergencies in the operations planning time horizon by analyzing the expected ***energy production capability of the available*** resource mix availability and ***its associated fuel supply*** the expected availability of fuel during the study period".

4.1 Functional entities

We suggest the standard be made applicable to all entities that are needed to provide data and forecasts, to ensure the assessments can be performed with up-to-date information. The standard must also especially apply to Generator Operators, as they may be required to take actions as dictated in the resulting mitigation plans.

R10.2

If The the ERA performed is a seasonal ERA**,** within 14 calendar days or;

Attachment 1

Should be moved up before the VSL matrix.

General

This is a good start. How severe or stressed the scenarios are, and how much energy margin is required can be debated and can evolve.

For R1.2.3.1, please clarify the word “availability” and the SDT intent, we are concerned about how auditors will audit this.

For R3, please clarify the word “unacceptable” and the SDT intent, we are concerned about how auditors will audit this.

Technical Rationale : page 5, figure 2, Mitigation Activities : missing the word “plan” in “implement Operating Associated with EOP-011…”. Furthermore, should “real-time” be capitalized?

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	
Document Name	

Comment

RF appreciates the efforts of the Standard Drafting Team on this project.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI.

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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Requirement R10 states: “The ERA comparison to the energy reserve margin requires the implementation of an Operating Plan(s) to mitigate risk within 24 hours for the near-term time horizon” but it is unclear if it is within 24 hours of the study being completed or the results reviewed. Similarly, in Requirement Part 10.2, it is unclear whether the BA shall provide the results of the seasonal ERA within 14 days of completion or review.	
Likes 0	
Dislikes 0	

Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute”	
Likes 0	

Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1	
Answer	
Document Name	
Comment	
Thank you to the SDT for your efforts in drafting BAL-007 and for considering the above comments. Manitoba Hydro recognizes the challenge of drafting a new standard that does not overlap with existing standards and avoids being being overly prescriptive or administratively burdensome.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
Requirement R5 indicates that the RC must review BA submission pursuant to R4 to determine Wide Area reliability risks. As R4 only requires BAs to submit information to its RC, BC Hydro requests the drafting team to clarify these expectations. Requirement R11 is not clear as to which information the RC must provide other BAs and TOPs in its RC Area, and neighboring RCs under the "notify … of the Implementation of an Operating Plan(s)". BC Hydro's understanding is that this is only a notification of the implementation of an Operating Plan and does not include the data behind it. Please clarify. Also, the "24 hours from the time of receiving notification" timeline seems unclear as the RC receives from a BA the results of the ERA and the comparison with the R8 energy reserves margin. Suggest rewording for clarity.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	
Document Name	
Comment	

PNMR supports removing the term “mitigation” from R3 and R10 as described in EEI’s comments.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Regarding R1.2.4. “Documented energy transfer assumptions”, given the context of R1.2 and the proposed BAL-007-1 in general, BPA interprets this to mean ‘energy imports/exports’. This interpretation reinforces BPA’s belief that these requirements do not belong in the BAL category of NERC reliability standards, as the BA does not initiate/engage in the import and export of block energy transaction.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	
Document Name	

Comment

Exelon supports the comments submitted by the EEI.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

Ameren agrees with and supports MISO's comments.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	

Comment

Florida Power and Light believes that the scope of this standard is redundant and excessive, thusly should not be approved based on its ambiguity of providing an increased reliability benefit. It is already part of each BA to utilize processes and procedures to assess the system to detect potential energy deficits, communicate to make known any imminent energy emergencies, and inform the need to implement mitigate energy emergencies. We strongly feel that an additional standard for assessment to determine forecasted energy issues would present an increased compliance burden on the Reliability Coordinator function as well as the BA to perform such studies.

Likes 0	
Dislikes 0	

Response

Helen Lainis - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

3. Purpose

Availability may be construed to mean Capacity Availability. As such, we propose the following revision:

"To assess and mitigate the risks of energy emergencies in the operations planning time horizon by analyzing the expected ***energy production capability of the available*** resource mix and ***its associated fuel supply*** during the study period".

4.1 Functional entities

We suggest the standard be made applicable to all entities that are needed to provide data and forecasts, to ensure the assessments can be performed with up-to-date information. The standard must also especially apply to Generator Operators, as they may be required to take actions as dictated in the resulting mitigation plans.

R10.2

If the ERA performed is a seasonal ERA **,** within 14 calendar days or;

Attachment 1

Should be moved up before the VSL matrix.

.**General**

This is a good start. How severe or stressed the scenarios are, and how much energy margin is required can be debated and can evolve.

Likes 0	
Dislikes 0	

Response

Dania Colon - Orlando Utilities Commission - 5

Answer	
Document Name	

Comment

Several terms are undefined or unclear and the excessive number of results produced from the currently prescribed ERA scenarios would be difficult to review and utilize by BAs and RCs. Requirements R5, R6, and R11 place undue administrative burden on RCs requiring excessive compiling of evidence to show compliance of the reviews and timely notifications. The amount of process document reviews and BA submitted ERAs will require a lot of additional support personnel without adding reliability value to the Bulk Power System.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the MRO NSRF for question #7.

Likes 0	

Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments:

"3. Purpose
Availability may be construed to mean Capacity Availability. As such, we propose the following revision:
"To assess and mitigate the risks of energy emergencies in the operations planning time horizon by analyzing the expected energy production capability of the available resource mix availability and its associated fuel supply the expected availability of fuel during the study period".
4.1 Functional entities
We suggest the standard be made applicable to all entities that are needed to provide data and forecasts, to ensure the assessments can be performed with up-to-date information. The standard must also especially apply to Generator Operators, as they may be required to take actions as dictated in the resulting mitigation plans.
R10.2
If The the ERA performed is a seasonal ERA, within 14 calendar days or;
Attachment 1
Should be moved up before the VSL matrix.
General
This is a good start. How severe or stressed the scenarios are, and how much energy margin is required can be debated and can evolve.
For R1.2.3.1, please clarify the word "availability" and the SDT intent, we are concerned about how auditors will audit this.
For R3, please clarify the word "unacceptable" and the SDT intent, we are concerned about how auditors will audit this."

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

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	
Document Name	

Comment

R3: SPP recommends consideration of including this in the BA Emergency Operating Plan.

R4: SPP recommends removing mutually agreed upon schedule and recommends providing on an annual basis and upon revision.

R9: SPP Recommends moving away from an ERA margin and focusing on evidencing when Operating Plans are utilized.

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 appreciate the Standards Drafting Team's (SDT) efforts to create the initial draft of this new Standard. Ensuring that Balancing Authorities monitor and maintain sufficient energy reserve margin is a good way to improve reliability.

The SDT should consider the following recommendations to revise and improve this reliability standard.

1) The SDT should create a new definition for Energy Reserve Margin (ERM) so that entities fully understand what energy reserves are being measured and used for comparisons to the newly defined ERA.

2) The SDT should also consider simplifying the calculations for ERM in Requirement R8 as follows:

- The minimum ERM is the estimated Operating Reserve (e.g. regulation reserve and contingency reserve) **plus** the greater of either, the largest unplanned N-1 resource contingency, or the largest load contingency in addition to the normal peak load (e.g. 1-in-2 peak load forecast). The largest load contingency is defined as the load forecast difference between the high peak load (e.g. 1-in-10 peak load forecast) and the normal peak load (e.g. 1-in-2 peak load forecast).

To improve reliability, this Standard should focus only on the seasonal ERA because TOP-002 and BAL-002 already adequately cover the near-term or operational ERA. In the near-term or operational ERA, the load forecast and planned/unplanned resource outage information are already pretty accurate and therefore, there is no need to carry additional energy reserves beyond the Operating Reserve. Carrying additional energy reserves is not necessary and is cost prohibitive for many entities.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 5

Answer	
Document Name	

Comment

3. Purpose

Availability may be construed to mean Capacity Availability. As such, we propose the following revision:

"To assess and mitigate the risks of energy emergencies in the operations planning time horizon by analyzing the expected ***energy production capability of the available*** resource mix availability and ***its associated fuel supply*** the expected availability of fuel during the study period".

4.1 Functional entities

We suggest the standard be made applicable to all entities that are needed to provide data and forecasts, to ensure the assessments can be performed with up-to-date information. The standard must also especially apply to Generator Operators, as they may be required to take actions as dictated in the resulting mitigation plans.

R10.2

If The the ERA performed is a seasonal ERA***,*** within 14 calendar days or;

Attachment 1

Should be moved up before the VSL matrix.

General

This is a good start. How severe or stressed the scenarios are, and how much energy margin is required can be debated and can evolve.

For R1.2.3.1, please clarify the word “availability” and the SDT intent, we are concerned about how auditors will audit this.

For R3, please clarify the word “unacceptable” and the SDT intent, we are concerned about how auditors will audit this.

Technical Rationale : page 5, figure 2, Mitigation Activities : missing the word “plan” in “implement Operating Associated with EOP-011…”. Furthermore, should “real-time” be capitalized?

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	

EEI suggests that the term “mitigate” be removed from this Reliability Standard because the BA and RC can only take actions to minimize impacts, they have no ability to modify or correct a resource issue. Please note the suggested changes to the Purpose statement, as well as Requirements R3 and R10 below (in bold face).

Purpose: To assess and **mitigate minimize** the risks of energy emergencies in the operations planning time horizon by analyzing the expected resource mix availability and the expected availability of fuel during the study period.

R3. Each Balancing Authority shall develop, maintain, and document one or more Operating Plan(s) to **mitigate minimize** unacceptable risk(s) associated with ERA scenario(s) with a likely event of occurring. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

R10. Each Balancing Authority shall provide the results of the ERA and the comparison of results from Requirement R9 to its Reliability Coordinator under the following conditions: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

{C}**10.1.** The ERA comparison to the energy reserve margin requires implementation of an Operating Plan(s) to **mitigate minimize the** risk**s** within 24 hours for the near-term time horizon or;

{C}**10.2.** {C}The ERA performed is a seasonal ERA within 14 calendar days or;

{C}**10.3.** {C}The Reliability Coordinator has requested the results.

Likes 0	
Dislikes 0	

Response

Robert Follini - Avista - Avista Corporation - 3

Answer	
Document Name	

Comment

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{C}**10.2.** {C}The ERA performed is a seasonal ERA within 14 calendar days or;

{C}**10.3.** {C}The Reliability Coordinator has requested the results.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1

Answer	
Document Name	

Comment	
See comments submitted by the Edison Electric Institute	
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	

3. Purpose

Availability may be construed to mean Capacity Availability. As such, we propose the following revision:

"To assess and mitigate the risks of energy emergencies in the operations planning time horizon by analyzing the expected ***energy production capability of the available*** resource mix availability and ***its associated fuel supply*** the expected availability of fuel during the study period".

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For R3, please clarify the word “unacceptable” and the SDT intent, we are concerned about how auditors will audit this.

Likes 0	
Dislikes 0	

Response

Marc Sedor - Seminole Electric Cooperative, Inc. - 3

Answer	
Document Name	

Comment

Seminole agrees with FRCC comments.

Can the SDT answer whether the following fuel sources must be considered for fuel contingencies if they are the fuel supply for a generator: (1) nuclear, (2) biomass, (3) waste to energy?

Marc Sedor, Seminole Electric 3/11/2024

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

NV Energy suggests that the term “mitigate” be removed from this Reliability Standard because the BA and RC can only take actions to minimize impacts, they have no ability to modify or correct a resource issue. Please note the suggested changes to the Purpose statement, as well as Requirements R3 and R10 below (in bold face).

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{C}**10.1.** {C}The ERA comparison to the energy reserve margin requires implementation of an Operating Plan(s) to **mitigate minimize the** risks within 24 hours for the near-term time horizon or;

{C}**10.2.** The ERA performed is a seasonal ERA within 14 calendar days or;

{C}**10.3.** The Reliability Coordinator has requested the results.

Likes 0	
Dislikes 0	

Response

Aaron Staley - Orlando Utilities Commission - 1

Answer	
Document Name	

Comment

See Tacoma Power comments.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI suggests that the term “mitigate” be removed from this Reliability Standard because the BA and RC can only take actions to minimize impacts, they have no ability to modify or correct a resource issue. Please note the suggested changes to the Purpose statement, as well as Requirements R3 and R10 below (in bold face).

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10.3. {C}The Reliability Coordinator has requested the results.

Likes 0	
Dislikes 0	

Response

LaKenya Vannorman - LaKenya Vannorman On Behalf of: Chris Gowder, Florida Municipal Power Agency, 5, 6, 3; Jade Bulitta, Florida Municipal Power Agency, 5, 6, 3; Navid Nowakhtar, Florida Municipal Power Agency, 5, 6, 3; - LaKenya Vannorman, Group Name Florida Municipal Power Agency (FMPA)

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Matthew Jaramilla, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	
Document Name	

Comment

SRP believes that the use of near-term in R1, R2, R8, R10 and R11 has the potential to create confusion in the industry as “Near-Term Transmission Planning Horizon” is already included in the NERC Glossary of Terms. Less confusion would occur if the SDT could use the recently updated NERC “Time Horizons” document and reference the Operations Planning Horizon or create a new term that allows for the distinction between Near Term Transmission Planning Horizon and the Near-Term Operating Horizon.

In addition, a BA doesn’t have infinite options to meet the energy reserve margins prescribed in R8. Our Operating Plans can only cover a set of finite options. R3 and R9 don’t really make this clear. One could infer that an Operating Plan is free to describe this aspect of mitigation steps. It may be better to modify R9 to “…if the energy reserve margins are not met, the Balancing Authority shall exhaust all available options from their applicable Operating Plan(s) developed in Requirement R3”.

Additionally, if this standard significantly increases reserve margin requirements, utilities may need more time than what is specified in the Implementation Plan. Even 24 or 36 calendar months to fully implement may not be enough as this may be 5 years or more to gather new generating resources. If the increased reserve margin requires new generating resource additions, the current market conditions for development of those resources may not be able to accommodate resource needs within the identified time period.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

For R4, AZPS recommends adding the information noted in bold below: The Balancing Authority shall submit the following information to its Reliability Coordinator for review on a mutually agreed-upon schedule **and data transfer method.**

For R5 & R6, AZPS recommends the SDT review the timelines as they are confusing. If there is anything the RC finds in an ERA, by the time BAs are required to respond would be outside of the ERA Period. Furthermore, R6. Measurement 6 is inconsistent with the Requirement of 60 and 30 days.

For R10.2, AZPS asserts that the intent is unclear and should be specified in the requirement. It is unclear if Balancing Authorities must be complete in 14 days or less, seasonal ERA with time period beginning 14 calendar days from the time it was performed. If a seasonal ERA was

Likes 0	
Dislikes 0	

Response

Keith Jonassen - Keith Jonassen On Behalf of: John Pearson, ISO New England, Inc., 2; - Keith Jonassen

Answer	
Document Name	

Comment

ISO-NE supports the comments from the SRC/IRC Council regarding GO/GOP requirements.

Any fuel requirements remain in the standard, the Generator Owner or Generator Operator must be required to provide all "depletion and replenishment of finite upstream resources (e.g., fuel)" to the BA along with any other fuel availability information needed by the BA to perform its ERA.

Utilizing TOP-003 R5 for this requirement puts the emphasis on the BA to repeatedly ask for the depletion and replenishment of resources without having direct knowledge of the fuel resource status. There should be a requirement for the GO/GOP to notify the BA of the status of finite resources if reliability or capability of the facility is affected.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

As currently drafted, the reliability benefit of the standard is unclear, and the standard could be understood to require BAs to shed load (or plan to shed load) even when there is no operational need to shed load. To the extent that an energy assurance reliability standard is needed, such a standard should focus on defining the risks that an ERA is intended to identify. It should not attempt to specify how the ERA should be performed, what thresholds should be used to determine whether a deficiency exists, or how the BA should address identified deficiencies. It also should not require BAs to obtain or make use of information that they do not have access to and have no way of accessing, such as information held by fuel transportation and delivery providers who are not subject to NERC or BA jurisdiction.

In other words, such a standard should allow BAs the flexibility to determine the best way to identify and address energy risks in their BA Areas. Adding additional requirements to TOP-002 might be a more effective way to accomplish this than creating a new BAL standard, as BAL standards typically relate to managing the frequency on the grid rather than ERA-type assessments.

To the extent that a standard is needed to address deficiencies identified by an ERA, energy assurance is ultimately a matter of resource adequacy, and other entities are in a better position than BAs to take action (particularly fuel- and supply chain-related action) to address potential energy deficiencies. Consequently, any requirements to take action to mitigate or address potential energy deficiencies should not be placed on BAs or RCs.

Additionally, use of the term "Operating Plans" may create the impression that actions to address potential energy deficiencies need to be implemented in real-time or emergency conditions. The use of a term such as "mitigation measures" or "risk reduction measures" would clarify that such actions could be implemented in advance of real-time or emergency conditions.

Finally, if the approach proposed in BAL-007 were to be adopted, the implementation period should be extended to 36 months to allow entities time to automate the ERA process.

Likes 0	

Dislikes 0	

Response

Jennifer Neville - Western Area Power Administration - 6

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	
Document Name	

Comment

IID believes that while it may be tempting to issue an additional standard which addresses the exact issues defined in the SAR for the sake of expediency, IID urges the SDT to take a more holistic and integrated approach by first analyzing and contemplate modifying the existing standards, where possible, prior to issuing a new standard.

Likes 0	
Dislikes 0	

Response

Colby Galloway - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company

Answer	
Document Name	

Comment

Southern Company supports the EEI comments and would add that a standard for assessment to determine forecasted energy issues should not present an increased compliance burden on the Reliability Coordinator function.

Southern Company maintains that the Reliability Coordinator should only be notified when there is an actual reliability issue OR upon request. Southern would suggest the below language changes to R10:

R10. Each Balancing Authority shall provide the results of the ERA to its Reliability Coordinator under the following conditions: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

10.1. The ERA **results indicate that a reliability issue that represents an imminent risk of an Energy Emergency and requires implementation of an Operation Plan(s) to minimize risk** or;

10.2. The Reliability Coordinator has requested the results.

Southern Company would assert the expectation that the RC will act in accordance with her/his duty to act established in IRO-001, R1, and additional compliance requirements are not needed. R11 should be struck or modified accordingly.

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. We are grateful for the tremendous effort put forth by the SDT to draft this new proposed standard.

Likes 0	
Dislikes 0	
Response	

Elizabeth Davis - Elizabeth Davis On Behalf of: Thomas Foster, PJM Interconnection, L.L.C., 2; - Elizabeth Davis, Group Name ISO/RTO Standards Review Committee

Answer	
Document Name	
Comment	

The IRC SRC raises four recommendations under this question.

1) Requirement for Generator Operators to provide upstream fuel data

2) Align the purpose of the proposed standard with the purpose stated in the companion Technical Rationale.

3) Allow 36 months for implementation of the ERA process.

4) Meet with the Resource Subcommittee prior to posting the next draft.

4.1 Functional entities

To the extent ERAs require information known by the Generator Owner or Generator Operator, the standard must require them to provide it to the BA to ensure the assessments can be performed with accurate and up-to-date information. To the extent that:

- Any fuel requirements remain in the standard, the Generator Owner or Generator Operator must be required to provide all “depletion and replenishment of finite upstream resources (e.g., fuel)” to the BA along with any other fuel availability information needed by the BA to perform its ERA.
- Any mitigation requirement remains in the standard, it should be placed on Generator Operators and Generator Owners, as these entities are best situated to take any mitigation actions that may be needed to address risks identified in ERA.

Standard Purpose: The SRC requests the Standard purpose reflect the purpose written in the Technical Rationale as it relates directly to the scope of this Project: The purpose of this standard is to assess energy risk in Operations Planning time horizon, determine if the risks are acceptable, and take actions to mitigate.

The SRC also recommends that the implementation time be changed to 36 months to allow enough time for BAs to develop methods to automate their ERAs.

Prior to posting the next draft, the SDT should meet with the NERC Resources Subcommittee (RS) to garner feedback. Since this is a BAL standard, and as the NERC RS is made up of BA subject matter experts, it would be worthwhile to ensure BAL-007 can pass muster. One of the RS’s primary responsibilities is to: “Review and assist in the development of interconnection balancing standards to assure problems resulting from balancing do not adversely affect reliability.”

The ISO RTO Council Standards Review Committee (IRC SRC) extends a huge thank you to NERC and the Standard Drafting Team in providing this update and all the work needed in completing this Project.

Likes 0	
Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	
Document Name	

Comment

MRO is not ready to vote affirmative for the following reasons:

1. Requirement Parts 2.1.4, 2.1.5, and 2.1.6 refer to "High load" as an ERA scenario condition/benchmark. Since the term "high load" is not planned for inclusion in the NERC glossary and there is no other clarification in the Standard regarding its meaning, there is significant opportunity for differences in professional judgement between registered entity and CEA staff regarding its meaning, thus making these Parts very difficult to enforce.

2. The language in R3 refers to "unacceptable risk(s) associated with ERA scenario(s)" and "likely event of occurring". Use of these quite general wordings without additional guidance on what bounds their interpretation creates significant opportunity for differences in professional judgement between registered entity and CEA staff regarding their meaning, thus making this Requirement very difficult to enforce.

Likes 0	
Dislikes 0	

Response

Holly Mitchell - NorthWestern Energy - NA - Not Applicable - WECC

Answer	
Document Name	

Comment

“Energy Reserve Margin” should be a defined term. Without a definition, it is not clear if this is associated with operating and/or contingency reserves or if it is independent. (This is made clearer under the technical justification of Requirements 8 and 9, but should be a defined term regardless.) There should be clarity provided for “required” versus “actual” energy reserve margin (e.g. R8 calculations are the “required” and the “results of the ERA” cited in R9 are “actual”.)
Per R9, “Each Balancing Authority shall compare results of the ERA to energy reserve margins in R8 […]”. The “results of the ERA” should be more explicitly defined—are the results intended to be solely “actual” energy reserve margin or is this just a component?

Likes 0	
Dislikes 0	

Response

C. A. Campbell - LS Power Development, LLC - 5

Answer	
Document Name	

Comment

We appreciate the SDT’s work and are in agreement with the proposed standard except for the issues described in our responses to #2 and #5.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	
Document Name	

Comment

See comments submitted by the Edison Electric Institute

Likes 0	
Dislikes 0	

Response

Darcy O'Connell - California ISO - 2

Answer	
Document Name	

Comment

In addition to supporting comments submitted by the ISO/RTO Counsel (IRC) Standards Review Committee, CAISO has the following comments:

- Propose to expand the applicability of this standard to entities that potentially need to provide data or assumptions to the BA for development of scenarios and plans. Add applicable entities that will need to provide RC with data and assumptions.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	
Document Name	

Comment

AECI has the following additional comments for the SDT to consider:

- This project attempts to establish a requirement for reliability studies, but there may be more effective ways approach energy assurance. While not specifically mentioned in the standard, LOLE study techniques measure unserved energy and can address this need. The LOLE analytical framework is relatively mature compared to what is described in the draft standard.
- The draft standard allows for both probabilistic (LOLE) and deterministic (scenario based) methods. This approach allows for flexibility and may be an appropriate choice but the results are vague requirements by allowing both techniques. For example, high loads, fuel contingencies are frequently included in the stochastic possibilities in a probabilistic study whereas the standard, as written, implies that scenarios are needed. More specificity in requirements would be beneficial where practical.
- Entities need additional time to implement the draft standard as many may not currently be performing similar studies. Additional staff, skillset development, and resources may need to be budgeted for,

Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	EEI Draft Comments _ Project 2022-03 BAL-007 Draft 1 Rev 0b 3_05_2024.docx
Comment	
Likes 0	
Dislikes 0	
Response	

Comments by Dwayne Howard at BHE Montana
Questions
1. The SDT has proposed a new Energy Reliability Assessment (ERA) definition which is intended to support the near-term and seasonal time horizons. Is the definition clear and understandable? If not, please provide the basis that supports your answer.
0 Yes
0 No
Comments:

2. The SDT developed a process that defines how both near-term and seasonal ERAs will be performed and specifies the requirements for both ERAs together. Are the process and the required parameters clear and understandable? If not, please provide the basis that supports your answer or suggestions for revisions. Please specify if comments are related to the near-term ERA, seasonal ERA, or both.
0 Yes
0 No
Comments: The standard does not allow for meeting the energy reserve margins through cooperative or sharing programs

3. The SDT proposes to require a set of scenarios to be developed which is needed in the performance of ERAs. Additionally, there is Attachment 1 that further supports the development of the set of scenarios. Are the scenarios specified in Requirement 2 the correct level or risk to consider in an ERA, and is the development of scenarios clear and understandable? If not, please provide the basis that supports your answer or suggestions for revisions. Please specify if comments are related to the near-term, seasonal ERA, or both.
0 Yes
0 No
Comments: Can scenarios allow Balancing Authorities to include cooperative or sharing programs

4. The SDT proposes entities determine energy reserve margins which would provide clear criterions for whether or not the results of an ERA require Operating Plan(s) to mitigate potential energy deficiencies. Are energy reserve margins the right method to set that criterion and are the specific energy reserve margin specified in Requirement 8 the correct thresholds for both near-term and seasonal ERAs? Is this approach clear and understandable? If not, please provide the basis that supports your answer or suggestions for revision.
0 Yes
0 No
Comments:

5. Does the proposed new standard address the reliability gaps or risks identified in the SAR and differentiate itself from other standard requirements? In your response, please provide any information that supports your answer.

0 Yes

0 No

Comments:

6. Is the proposed standard practicable to:

i. Be implementable?

ii. Is the proposed standard auditable?

iii. Able to comply with?

In your response, please provide any information that supports your answer.

0 Yes

0 No

Comments: **Would ask that the Standard Drafting Team (SDT) please address the applicability of the proposed standard to "Generation Only" Balancing Authorities. As an example, a Generation Only Balancing Authority Area does not have any load, and as such would not be able to develop any of the "Reliability Coordinator ERA scenarios" as required by Requirement 2.**

7. Provide any additional comments for the SDT to consider, if desired.

Comments:

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Response to Comments - Draft 1

NERC Project 2022-03 Energy Assurance with Energy-Constrained Resources

May 2024

RELIABILITY | RESILIENCE | SECURITY




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

Table of Contents

Introduction

NERC Project 2022-03 Energy Assurance with Energy-Constrained Resources drafting team (DT) is addressing energy assurance. This project will enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and when predefined criteria are not met, develop Corrective Action Plan(s), Operating Plans, or other mitigating actions to address identified risks. Energy reliability assessments evaluate energy assurance across the operations time horizons by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.

There were 57 sets of responses, including comments from approximately 186 different people from approximately 109 companies representing 10 of the industry Segments.

Additional information is available on the project page.

Background

Based on industry feedback, the standard drafting team (SDT) modified the ERA definition. In addition, determined that near-term ERAs and seasonal ERAs would be better suited in separate standards. The team kept near-term ERAs in BAL-007-1 and created a new BAL-008-1 to address seasonal ERAs. The purpose of this change was to make each requirement clearer about what applied to each standard and allow for two ERAs to be better distinguished. Please refer to the BAL-007-1 and BAL-008-1 Technical Rationale documents for additional justification and information regarding requirements within the proposed standards.

Response to Comments Document Layout

The DT will be responding to all comments in a summary response report. Each chapter covers topics identified throughout the comments received (e.g., Applicability, Definition, Administrative, Requirements, etc.). Comments received are outlined at a high level in each chapter followed by the drafting team's response on how it considered the comment and the outcome of how the comment was addressed. If you have any questions, please contact Standards Developer, Jordan Mallory (Jordan.mallory@nerc.net).

Thank You

The drafting team thanks industry for your time in reviewing the proposed BAL-007-1 standard and providing comments and proposals for the drafting team's consideration. All comments received have been reviewed and discussed. Response to comments have been drafted in a summary response.

Definitions

Energy Reliability Assessment Definition

Draft 1[1] proposed definition:

> ***Energy Reliability Assessment (ERA) -*** *Evaluation of the resources that supply electrical energy and ancillary services for the Bulk Power System to reliably meet the expected demand during the associated time period. ERAs account for the impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).*

Industry comments:

- Many commenters questioned the need for the second sentence of the ERA definition, which is shown above. Concerns expressed that this sentence provides confusion and zero clarity.
- Industry commenters questioned if the term "demand" in the ERA definition was supposed to be capitalized using the defined term from the NERC Glossary of Terms.
- Only include registered Bulk Power System resources.
- What does "ancillary services" mean?
- Add definition to Technical Rationale document.

Drafting team response:

The DT removed the second sentence based on the majority of industry expressing that it does not add any clarity and capitalized the term demand used within the ERA definition to be consistent with the defined term from the NERC Glossary. Since the ancillary service of concern to the DT was Operating Reserves, "ancillary services" has been replaced with "Operating Reserves." The DT determined to not include only registered resources as the resource mix is moving to include more unregistered resources.

Below provides the updated proposed ERA definition that will be posted with Draft 2.

> ***Energy Reliability Assessment (ERA) -*** *Evaluation of the resources to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated evaluation period.*

In addition, the DT will add a definition section to the Technical Rationale (TR) document explaining the rationale behind this definition. Please see the updated TR posted with draft 2.

[1] Posted for comment and ballot period January 25 – March 11, 2024 (Project page: [Project 2022-03 Energy Assurance with Energy-Constrained Resources (nerc.com)]())

Administrative

Results-based Standard and Requirement Flexibility

There were many industry concerns that the BAL-007-1 Standard was not drafted to a results-based level. In addition, industry shared concerns about the requirements being very prescriptive and the need to allow for flexibility.

Drafting team response:

The DT modified the requirements to fit the results-based standard guidance document and took the level of prescriptiveness up to provided entities with flexibility to meet the differences throughout the United States and Canada business models.

This standard enhances Balancing Authorities analysis and establishes the requirement for communicating forecasted events to the Reliability Coordinators with an Operating Plan. The Balancing Authority can customize the Energy Reliability Assessment (ERA) to determine the forecasted credible risk. The Balancing Authority evaluates the forecasted ERA, analyzes the risk of the energy shortage based on the extent of its magnitude and timing. To meet regional demands, Balancing Authorities must define their own scenarios as well as define what risks they will deem as credible. Providing the Balancing Authority with the ability to define the credible forecasted risk will ensure clarity in priorities and eliminate unnecessary plans at the Reliability Coordinators level. The Balancing Authority's notification to the Reliability Coordinator of an expected reliability event helps in dealing with real problems and fulfilling NERC Operating Plan responsibilities to improve reliability by making decisions that prevent or resolve emergency events.

Redundancy with other Standards

Many industry comments were concerned about the redundancy from other standards (TOP-002, BAL-002, BAL-003, etc.)

Drafting team response:

The SDT has clarified the difference between this standard and others including TOP-002 and EOP-011 through language changes and adding greater clarity in the technical rationale.

- The period for near-term ERA was changed in R1 so that beginning of the period is clearer (up to two days after present day) that the ERA does not need to overlap with TOP-002 Operations Planning Analysis.
- The term, "forecasted Energy Emergency" was used in the document for consistency and to differentiate from actual or imminent Energy Emergencies that have Operating Plans and are declared under EOP-011.
- The SDT believes the proposed standards are differentiated from BAL-002 and BAL-003 by the time horizon and focus on sufficient energy instead of response to and recovery from Contingencies in real-time. Connecting the conditions for forecasted Energy Emergencies in R8 with the Energy Emergency Alert conditions in Attachment 1 of EOP-011 should help further clarify that the consideration for ERAs is having insufficient energy that could result in loss of load.
- The SDT added additional description of how the BAL-007-1 and BAL-008-1 standards differentiate from other standards to the technical rationale (see the Rationale for each standard along with the Relationship to Other Standards sections).

Reliability Benefit

Many entities questioned the reliability benefit for this project and asked that the DT make it clear.

Drafting team response:

By implementing the standard, the Balancing Authority can proactively make reliability decisions based on energy and fuel constraints before an emergency occurs.

Feedback

Some commenters requested the DT seek feedback from Resource Subcommittee prior to posting the next draft.

Drafting team response:

The drafting team circulated the proposed draft 2 to the resource subcommittee prior to going out for its second ballot.

Applicability

Add Applicable Entities

Some entities expressed concern about the Balancing Authority not having the authority to gather information needed to meet the BAL-007-1 standard. It was suggested the team consider including additional entities like Load Serving Entity (LSE)/Load Responsible Entity (LRE), Resource Planners, and GOPs as applicable entities, Resource sharing groups.

Drafting team response:

The DT reviewed TOP-003 and determined that entities should be able to request the data needed to be compliant with BAL-007-1 and the newly proposed BAL-008-1. The team did discuss and agreed that resource planners are not applicable to TOP-003 and should be added to BAL-008-1 to assist Balancing Authorities to gather information needed for seasonal ERAs.

Requirements

Flexibility

Entities request flexibility in many aspects of the requirement language. Below lists the following high-level flexibility requests, allowing for:

- Probabilistic models and analysis.
- dynamic data-driven scenarios.
- accommodating a variety of approaches.

Drafting team response:

The drafting team has completely rewritten R2 to accommodate a variety of approaches where the Balancing Authority (BA) determines the Scenarios or methods for generating Scenarios that stress system conditions. Industry feedback emphasized the importance of BAs determining the scenarios to alleviate worries about excessively studying high-risk, low-probability scenarios. The revised language allows for probabilistic analysis and dynamic data-driven scenarios as requested per industry comments. Consequently, changes also address concerns regarding the clarity of "high load" scenarios and the intention behind studying energy and fuel supply contingencies.

Requirement R1

Near-term ERA Clarity

Many commenters asked the drafting team what it meant by near-term throughout the standard to define what it means.

Drafting team response:

After completing an exercise of drafting a proposed near-term ERA definition, the team determined that the proposed definition was better suited within the requirement language and not as a standalone definition. A near-term ERA is an ERA that must have a duration between five days and six weeks and begin no later than two days after the present operating day. The frequency of near-term ERA must be at intervals that ensure all time periods are covered by a near-term ERA. Please see the updated TR for additional information.

Seasonal ERA Definition

Many commenters asked the drafting team what it meant by seasonal throughout the standard to define what it means.

Drafting team response:

The drafting team modified separate near-term ERAs and seasonal ERAs into a new standard for both: one near term and one seasonal. Within each standard, requirements have been modified to specify the definition of the time frame and duration for each ERA. A number of changes were made to both the season definition and the allowable duration of the defined seasons. Please see the updated TR for additional information.

Requirement R2/Scenarios

The drafting team received numerous comments about the scenarios. The comments ranged from too extreme to not extreme enough, but the predominant message was that most entities prefer the BA be allowed to determine its own scenarios based upon its individual circumstances.

Drafting team response:

The drafting team changed the language referring to the fuel contingency to allow the BA to define a credible fuel contingency that is appropriate for its own BA area. The amount of information needed by the BA to determine its credible fuel contingency is defined by each BA. The drafting team also changed the language referring to the energy supply contingency to allow the BA to define a credible energy supply contingency that is appropriate for its own BA area. The amount of information needed by the BA to determine its credible energy supply contingency is defined by each BA. Information required to determine the contingencies may be obtained through the BAs data specification document which is required under TOP-003.

Requirement R5 and R6

- Timelines do not support ERA scenarios provided or any operating plans.
- R5 and R6: 60-day review may be too long for a review.
- Check Measure Requirement R6… stated 30 and not 60 as stated in the requirement.

Drafting team response:

The drafting team reviewed the requirements and decided to keep the 60 days. While for many BAs and RCs, 60 days is significantly longer than will most likely be required. However, for RCs with a larger number of BAs within their footprint, the drafting team feels the allowable 60-day time is appropriate (new R6). The 60-day time frame has been provided for BA revisions to provide sufficient time to make any necessary changes (new R7). BAs within a common RC footprint may have more requested changes to address; the drafting team has provided time to accommodate this situation.

Requirement R8

Many comments expressed concern that Requirement R8 has been drafted to a very prescriptive level and the requirements are not realistic for smaller Balancing Authorities and does not provide the necessary flexibility for other Balancing Authorities.

Drafting team response:

Requirement 8 has been updated in the latest draft standard to be fundamentally in alignment with the Energy Emergency Alert (EEA) definitions from EOP-011, Attachment 1, Section B. These are well-understood and accepted criteria and offer the same flexibility as the current implementation of EOP-011.

It would be expected that a BA would define their forecasted EEA criteria using the same definitions as EEA criteria, meaning that if they are relying on a reserve sharing group to meet EOP-011 EEA criteria, then meeting the forecasted EEA criteria would have the same definition, allowing for the use of RSGs (Reserve Sharing Groups).

To draw separation between BAL-007-1 and EOP-011, Requirement 1 of BAL-007-1 was updated to reflect that an ERA begins “no later than two days after the present operating day”, indicating that the BAL-007-1 time period is further out than the EOP-011 time period.

Notifications between entities should be a common practice when forecasting Energy Emergencies.

Operating Plans

- Will the requirements require a lot of operating plans?
- Operating plans are ambiguous within the requirements.

Drafting team response:

The SDT understands the concern that specific Operating Plans developed ahead of time may change for actual events. However, the SDT believes that the Operating Plans that are useful for looking out to the near-term horizon and the seasonal horizon can be sufficiently general or a list of processes or activities that can be performed rather than specific actions that need to be done. For near-term ERAs, the Operating Plan would be developed for multi-day actions rather than actions that would occur in real-time if an Energy Emergency actually occurs, and the Balancing Authority has the flexibility to include in its Operating Plan only the actions that make sense to perform over that time period and up next day or day of the event (real-time). Similarly, for the seasonal ERA, the Balancing Authority can develop Operating Plans that include the possible actions that can occur over months to reduce risk before the seasonal period.

Deterministic versus Probabilistic

Some entities questioned if the requirement language was drafted at a level that allowed for probabilistic analysis.

Drafting team response:

In general, the SDT attempted to incorporate suggestions from the comments and remove prescriptive language where it was deemed necessary and not adding value. Examples of this can be seen in Requirement 1, 2, and R8. Specifically, to allow for probabilistic vs. deterministic analysis, the SDT believes that either and/or both types of modeling would be acceptable in meeting the requirements of the Standard.

Too Prescriptive Language

Some entities questioned if the requirement language was drafted at a level that allowed for probabilistic analysis.

Drafting team response:

The SDT believes it could be a significant effort to develop probabilistic and/or deterministic modeling (in either the near term or seasonal time frame) for entities that may not already be performing analysis in line with the Standard and therefore the effective date was extended from 12 to 18 months for the near-term ERA and 18 to 24 months for the seasonal ERA.

Small Balancing Authorities/Sharing Groups

Some comments expressed concern that the proposed requirements do not take small Balancing Authorities into consideration. In addition, commenters expressed that the DT should take into consideration Reserve Sharing Groups and Western Resource Adequacy Program (WRAP) type groups when drafting requirements for entities who use these types of groups.

Drafting team response:

The drafting team has addressed this concern through two notable adjustments. Firstly, R2 has been revised to accommodate Scenarios or methods for creating Scenarios to be determined by Balancing Authorities (BA). Secondly, R9 has been revised to evaluate ERA results against conditions outlined in EOP-011 Attachment 1 Section B. These circumstances are familiar to BAs and are relevant across the full spectrum of BA sizes.

The SDT believes that BAs have the ability to define the ERA process as needed to fit their specific characteristics and requirements. R1-R4, R8, and R9 all allow the BA to develop the methodology, identify the risk, set criteria, and develop mitigation strategies for the ERA. The SDT debated adding language to R.1 stating “Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document” but decided that latitude is implied and will add additional detail in the Technical Rationale to support the consideration of the comments received.

Inter-Balancing Authority Energy Transfers

Some entities were concerned that there was a reliability gap because energy transfers between neighboring Balancing Authorities were not included explicitly in the standards.

Drafting team response:

The SDT added the text, "energy transfers between neighboring Balancing Authorities" to the list of near-term ERA elements in Requirement R1.3.1 to address this concern.

Technical Rationale

Industry comments:

Many entities request the technical rationale document be updated regarding many aspects of the standard.

- Attachment 1 should be moved to TR.
- Clarity around individually or jointly regarding Requirement R1.
- Various aspects such as the handling of “high load” scenarios, the persistence of contingencies throughout the assessment period, and the intention behind studying certain types of contingencies.

Drafting team response:

See the updated Technical Rationale, which addresses industry comments requesting additional clarifications or justification.

The drafting team removed Attachment 1 as a part of the changes allowing Balancing Authority’s to define their own scenarios. In addition, the language related to contingencies was also changed to specifically refer to an energy supply Contingency and a fuel supply contingency to help differentiate between the energy contingency and the Balancing Authority’s Most Severe Single Contingency (MSSC) which may not be the unit providing the most energy during the study period.

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Reminder

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Initial Ballot and Non-binding Poll Open through March 11, 2024

Now Available

Initial ballots for draft one of **BAL-007-1 – Energy Reliability Assessments** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, March 11, 2024**.

Reminder Regarding Corporate RBB Memberships

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

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

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

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

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

For more information or assistance, contact Standards Developer, Dominique Love (via email) or at 404-217-7578. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources 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

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Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Formal Comment Period Open through March 11, 2024
Ballot Pools Forming through February 23, 2024

Now Available

A 45-day formal comment period for draft one of **BAL-007-1 – Energy Reliability Assessments** is open through **8 p.m. Eastern, Monday, March 11, 2024.**

Commenting

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

Reminder Regarding Corporate RBB Memberships

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

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Friday, February 23, 2024.** Registered Ballot Body members can join the ballot pools here.

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

Next Steps

Initial ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **March 1 - 11, 2024**.

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

For more information or assistance, contact Standards Developer, Dominique Love (via email) or at 404-217-7578. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources observer list” in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/313)
Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 IN 1 ST
Voting Start Date: 3/1/2024 12:01:00 AM
Voting End Date: 3/11/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 238
Total Ballot Pool: 265
Quorum: 89.81
Quorum Established Date: 3/11/2024 2:39:49 PM
Weighted Segment Value: 6.08

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	2	0.038	50	0.962	0	14	9
Segment: 2	8	0.7	1	0.1	6	0.6	0	1	0
Segment: 3	58	1	1	0.021	46	0.979	0	7	4
Segment: 4	9	0.7	0	0	7	0.7	0	1	1
Segment: 5	63	1	3	0.065	43	0.935	0	9	8
Segment: 6	44	1	1	0.028	35	0.972	0	4	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	0	1
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.4	1	0.1	3	0.3	0	3	0
Totals:	265	5.8	9	0.353	190	5.447	0	39	27

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		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		Negative	Third-Party Comments
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		None	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		None	N/A
1	NB Power Corporation	Jeffrey Streifling		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	Abstain	N/A
1	Orlando Utilities Commission	Aaron Staley		Negative	Comments Submitted
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		None	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Third-Party Comments
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Negative	Third-Party Comments
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Negative	Third-Party Comments
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Abstain	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	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Orlando Utilities Commission	Ballard Mutters		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
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		None	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
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	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		None	N/A
4	Northern California Power Agency	Marty Hostler		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	American Municipal Power	Amy Ritts		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Pamela Van Calcar		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Calpine Corporation	Whitney Wallace		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Electric Power Supply Association	Bill Zuretti		Abstain	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
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	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Comments Submitted
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Negative	Third-Party Comments
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		None	N/A
5	Platte River Power Authority	Jon Osell		None	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Abstain	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		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	Brandon Smith	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Kelly Bertholet		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Negative	Third-Party Comments
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Negative	Comments Submitted
10	New York State Reliability Council	Wesley Yeomans		Abstain	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/313)
Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources Implementation Plan IN 1 OT
Voting Start Date: 3/1/2024 12:01:00 AM
Voting End Date: 3/11/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 230
Total Ballot Pool: 257
Quorum: 89.49
Quorum Established Date: 3/11/2024 3:08:35 PM
Weighted Segment Value: 11.58

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	3	0.06	47	0.94	0	16	9
Segment: 2	8	0.7	1	0.1	6	0.6	0	1	0
Segment: 3	54	1	2	0.048	40	0.952	0	8	4
Segment: 4	9	0.7	0	0	7	0.7	0	1	1
Segment: 5	59	1	4	0.095	38	0.905	0	9	8
Segment: 6	44	1	2	0.057	33	0.943	0	5	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	0	1
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.3	3	0.3	0	0	0	4	0
Totals:	257	5.7	15	0.66	171	5.04	0	44	27

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		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		Negative	Third-Party Comments
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		None	N/A
1	Lower Colorado River Authority	Matt Lewis		None	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Third-Party Comments
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		None	N/A
1	NB Power Corporation	Jeffrey Streifling		Negative	Third-Party Comments
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Negative	Third-Party Comments
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	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	Negative	Comments Submitted
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		None	N/A
1	SaskPower	Wayne Guttormson		None	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Third-Party Comments
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Negative	Third-Party Comments
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Negative	Third-Party Comments
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
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		Negative	Third-Party Comments
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Orlando Utilities Commission	Ballard Mutters		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Negative	Third-Party Comments
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	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		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		None	N/A
4	Northern California Power Agency	Marty Hostler		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Negative	Third-Party Comments
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	American Municipal Power	Amy Ritts		Negative	Third-Party Comments
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Pamela Van Calcar		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Calpine Corporation	Whitney Wallace		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
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	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	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	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		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		Negative	Third-Party Comments
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Abstain	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman	Brandon Smith	Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Third-Party Comments
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Kelly Bertholet		Affirmative	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		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		Negative	Third-Party Comments
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Abstain	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		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Showing 1 to 257 of 257 entries

BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 | Non-binding Poll IN 1 NB
Voting Start Date: 3/1/2024 12:01:00 AM
Voting End Date: 3/11/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 213
Total Ballot Pool: 246
Quorum: 86.59
Quorum Established Date: 3/11/2024 3:18:01 PM
Weighted Segment Value: 5.49

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	72	1	2	0.048	40	0.952	19	11
Segment: 2	7	0.6	1	0.1	5	0.5	1	0
Segment: 3	53	1	0	0	38	1	11	4
Segment: 4	9	0.7	0	0	7	0.7	1	1
Segment: 5	56	1	2	0.054	35	0.946	9	10
Segment: 6	41	1	1	0.033	29	0.967	5	6
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1
Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	7	0.4	3	0.3	1	0.1	3	0
Totals:	246	5.7	9	0.535	155	5.165	49	33

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		None	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		None	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Austin Energy	Thomas Standifur		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Negative	Comments Submitted
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		Abstain	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte		Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		None	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		None	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker		None	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	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Abstain	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	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	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		None	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sho-Me Power Electric Cooperative	Olivia Olson		Abstain	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Negative	Comments Submitted
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		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	Comments Submitted
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		None	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs	Carly Miller	Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Negative	Comments Submitted
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Abstain	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
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		Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		None	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Orlando Utilities Commission	Ballard Mutters		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		Abstain	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	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		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
4	DTE Energy	Patricia Ireland		None	N/A
4	Northern California Power Agency	Marty Hostler		Abstain	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Negative	Comments Submitted
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
5	AEP	Thomas Foltz		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Pamela Van Calcar		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
5	Calpine Corporation	Whitney Wallace		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Helen Wang		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Abstain	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Negative	Comments Submitted
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi		Negative	Comments Submitted
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	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		None	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		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	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		None	N/A
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 Snohomish County	Becky Burden		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		Negative	Comments Submitted
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		None	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
6	AEP	Mathew Miller		None	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman	Brandon Smith	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Abstain	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		Negative	Comments Submitted
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Negative	Comments Submitted
6	Lakeland Electric	Paul Shipps		Negative	Comments Submitted
6	Lincoln Electric System	Eric Ruskamp		None	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		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Comments Submitted
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	None	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Negative	Comments Submitted
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		Negative	Comments Submitted
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 246 of 246 entries

Standard Development Timeline

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

Description of Current Draft

This is the initial 45-day formal comment period with ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022

Anticipated Actions	Date
45-day formal comment period with initial ballot	May 7 – June 20, 2024
45-day formal comment period with additional ballot	September 10 – October 24, 2024
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 13, 2024

A. Introduction

1. **Title:** Seasonal Energy Reliability Assessments

2. **Number:** BAL-008-1

3. **Purpose:** To assess the risks associated with Energy Emergencies in the seasonal time horizon and take appropriate actions to address identified risk. As the Bulk-Power System becomes more reliant upon energy-constrained and variable resources, traditional capacity-based planning methods and strategies might not identify energy-related risks to reliable System operation.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   4.1.2. Reliability Coordinator

   4.1.3. Resource Planner

5. **Effective Date:** See Implementation Plan for BAL-008-1.

B. Requirements and Measures

R1. Each Balancing Authority shall document and maintain a process for conducting Energy Reliability Assessments (ERA) for the seasonal time horizon. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The Balancing Authority shall define its seasons, which do not have to align with traditional seasonal definitions but must cover an entire calendar year.

1.2. The seasonal ERAs will be representative of the risks or conditions within each seasonal period. The Balancing Authority will determine the duration for each seasonal ERA to represent those risks or conditions and does not need to include all hours in the seasonal period.

1.3. The Balancing Authority shall define a periodicity for conducting the seasonal ERAs, that provides for completion at least 30 calendar days prior to but no greater than 12 months before the beginning of each season.

1.4. The ERA process for seasonal ERAs must account for the following:

1.4.1. Forecasted or assumed Demand profiles;

1.4.2. Resource capabilities and operations, including depletion of fuel, variable energy resources, (e.g., wind, solar, and hydro) energy transfers between neighboring Balancing Authorities, and electric storage; and

1.4.3. Transmission Constraints that limit the ability of generation Facilities to deliver their output to Load.

1.5. The ERA process for seasonal ERAs shall include the rationale for each of the elements in Parts 1.1 through 1.4.

M1. Each Balancing Authority shall have evidence that it documented and maintained a process for conducting seasonal ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall document and maintain a set of Scenarios or method of Scenario creation for use in performing seasonal ERAs. Each Scenario or method shall vary one or more of the following conditions to stress its System within a range of credible situations. Include a rationale for the Scenarios or method identified. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Forecasted or assumed Demand profiles;

2.2. Resource capabilities and operations including the following:

2.2.1. The effects of a credible energy supply Contingency;

2.2.2. The effects of a credible fuel supply Contingency; and

2.2.3. Unplanned generator outages.

2.3. The effects of other contingencies with a credible or historical risk of occurring based on the best information available at the time of Scenario creation.

M2. Each Balancing Authority shall have evidence that Scenarios or methods were developed and maintained along with a documented rationale in accordance with Requirement R2.

R3. Each Balancing Authority shall document and maintain one or more Operating Plan(s) to minimize forecasted Energy Emergencies, as identified in the seasonal ERA, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it documented and maintained its Operating Plan(s) in accordance with Requirement R3.

R4. Each Balancing Authority shall maintain a documented specification for the data necessary from its Resource Planners to perform seasonal ERAs. The data specification shall include the following: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

4.1. A list of data and information needed by the Balancing Authority to support its seasonal ERAs;

4.2. A periodicity for providing data;

4.3. The deadline by which the respondent is to provide the indicated data.

M4. Each Balancing Authority shall have evidence of its documented data specification detailing the necessary data it needs from its Resource Planners to perform seasonal ERAs, in accordance with Requirement R4.

R5. Each Balancing Authority shall distribute its data specification to its Resource Planner(s) that have data required by the Balancing Authority to perform its seasonal ERAs. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence showing that it provided the data specification required for its seasonal ERAs to its Resource Planner(s) in accordance with Requirement R5.

R6. Each Resource Planner receiving a data specification in Requirement R5 shall satisfy the obligations of the documented specifications using: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

6.1. A mutually agreeable format;

6.2. A mutually agreeable process for resolving data conflicts; and

6.3. A mutually agreeable data security protocol.

M6. Each Resource Planner shall have evidence that it has satisfied the data specifications received from the Balancing Authority by providing the appropriate data needed to perform the seasonal ERA, in accordance with Requirement R6.

R7. The Balancing Authority shall review and update, if necessary, its seasonal ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it reviewed its seasonal ERA process, Scenarios or methods, and Operating Plan(s) and submitted the information to its Reliability Coordinator at least once every 24 months, in accordance with Requirement R7.

R8. Each Balancing Authority shall provide its seasonal ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M8. Each Balancing Authority shall have evidence it provided its seasonal ERA process, Scenarios, or methods, and Operating Plan(s) documented under Requirement R1 through R3 to its Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule, in accordance with Requirement R8.

R9. Within 60 calendar days of receipt of the information in Requirement R8, the Reliability Coordinator shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning].*

9.1. Review each submittal for coordination with other Balancing Authorities' ERA information to avoid risks to Wide Area reliability; and

9.2. Notify each Balancing Authority of the results of its review and, if revisions are needed, to address reliability risks.

M9. Each Reliability Coordinator shall have evidence that it reviewed each submittal and notified each Balancing Authority of the results of the review within 60 days of receiving a submittal from Requirement R9.

R10. Within 60 calendar days of receipt of the Reliability Coordinator's notice under Requirement R9, each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit the updated information required in Requirement R8 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M10. Each Balancing Authority shall have evidence that it addressed any reliability risks identified by its Reliability Coordinator and resubmitted updated information to its Reliability Coordinator within 60 days of receipt of notice from Requirement R10.

R11. Each Balancing Authority shall perform seasonal ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M11. Each Balancing Authority shall have evidence that it performed the seasonal ERAs in accordance with Requirement R11.

R12. If a seasonal ERA identifies one or more of the forecasted Energy Emergencies listed below, the Balancing Authority shall implement an Operating Plan(s), as documented in Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Forecasted EEA1 circumstances as defined in EOP-011 Attachment 1 Section B
- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B

M12. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) in accordance with Requirement R12.

R13. Each Reliability Coordinator, within seven calendar days of receiving a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R8, shall notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of the forecasted condition(s) and the Balancing Authority's Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M13. Each Reliability Coordinator shall have evidence demonstrating it communicated, within seven calendar days from the time of receiving notice of implementation of a Balancing Authority's Operating Plan, with the other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators in accordance with Requirement R13.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Balancing Authority and Reliability Coordinator shall keep data or evidence to show compliance with applicable requirements for six months for near-term time horizon and 18 months for the seasonal time horizon or since the last audit.

   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 Balancing Authority documented an ERA process document for the seasonal time horizon accounting for each of the elements in Requirement R1 Parts 1.1 through 1.4 but failed to maintain it at least annually.	The Balancing Authority documented and maintained an ERA process document for the seasonal time horizon but did not account for one or more of the elements under Requirement R1 Part 1.4. OR The Balancing Authority documented a seasonal ERA process but did not provide a supporting rationale(s) under Requirement R1 Part 1.1 and Part 1.4 for the seasonal time horizon.	The Balancing Authority documented and maintained an ERA process document for the seasonal time horizon but failed to include two or more of the required elements under Requirement R1 Part 1.4 or supporting rationale(s) under Requirement R1 Part 1.1 and Part 1.4 for the seasonal time horizon. OR The Balancing Authority failed to document an ERA process for the seasonal time horizon.
R2.	N/A	The Balancing Authority documented the seasonal ERA set of Scenarios or method of Scenario creation but failed to maintain them. OR The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include a	The Balancing Authority documented and maintained the seasonal ERA set of Scenarios or a method of Scenario creation but failed to include one of the Scenarios or method of Scenario creation in Requirement R2 Part 2.1, Part 2.2 and Part 2.3 or supporting rationales under Requirement R2.	The Balancing Authority documented and maintained the seasonal ERA set of Scenarios or a method of Scenario creation but failed to include two or more of the Scenarios in Requirement R2 Part 2.1, Part 2.2, and Part 2.3 or supporting rationales under Requirement R2. OR

		rationale for the Scenarios or method identified.		The Balancing Authority failed to document the seasonal ERA set of Scenarios or a method of Scenario creation.
R3.	N/A	N/A	The Balancing Authority documented and maintained Operating Plan(s) but failed to include a provision for notification for its Reliability Coordinator.	The Balancing Authority failed to develop Operating Plan(s) to minimize forecasted Energy Emergencies identified in the seasonal ERAs.
R4.	N/A	N/A	The Balancing Authority maintained a documented data specification for the seasonal ERA but failed to include one of the elements in Requirement R4 Part 4.1, Part 4.2, and Part 4.3.	The Balancing Authority maintained a documented data specification for the seasonal ERA but failed to include two or more of the elements in Requirement R4 Part 4.1, Part 4.2, and Part 4.3. OR The Balancing Authority failed to document a data specification for the seasonal ERA.
R5.	N/A	N/A	N/A	The Balancing Authority failed to distribute its data specification to its Resource Planner(s) that have data required by its Balancing Authority for its seasonal ERA.

R6.	N/A	N/A	N/A	The Resource Planner failed to satisfy the obligations of the documented data specification.
R7.	N/A	N/A	The Balancing Authority reviewed the seasonal ERA process, the seasonal ERA Scenarios or methods of Scenario creation, and Operating Plan(s) but failed to update its Reliability Coordinator within the mutually agreed-upon schedule.	The Balancing Authority failed to review or update information that contained the seasonal ERA process, the seasonal ERA scenarios or methods of Scenario creation, and Operating Plan(s) to its Reliability Coordinator.
R8.	N/A	N/A	The Balancing Authority submitted information that contained the seasonal ERA process, the ERA Scenarios, and Operating Plan(s) but failed to submit to the Reliability Coordinator within 24 months, on a mutually agreed-upon schedule.	The Balancing Authority failed to submit information that contained the seasonal ERA process, the ERA Scenarios, and Operating Plan(s) to the Reliability Coordinator.
R9.	N/A	N/A	The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' seasonal ERA information to avoid risks to Wide Area reliability but failed to notify each Balancing Authority of	The Reliability Coordinator failed to review the information in Requirement R8 for coordination with other Balancing Authorities' seasonal ERA information to avoid risks to Wide Area reliability.

			results of its review within 60 calendar days.	
R10.	N/A	N/A	The Balancing Authority addressed any reliability risks identified by its Reliability Coordinator and resubmitted the updated information required in Requirement R7 to its Reliability Coordinator but resubmitted the updated information more than 60 calendar days following receipt.	The Balancing Authority failed to address any reliability risks identified by its Reliability Coordinator. OR The Balancing Authority failed to resubmit the updated information required in Requirement R7 to its Reliability Coordinator.
R11.	N/A	N/A	N/A	The Balancing Authority failed to perform seasonal ERAs in accordance with its process documented in Requirement R1 using the Scenarios or methods of Scenario creation documented in Requirement R2.
R12.	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s)when a seasonal ERA identified any of the forecasted conditions in Requirement R12.

R13.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R12 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 24-48 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R12 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 48-72 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R12 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinator Area between 72-96 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R12 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordaintors of the forecasted condition(s) and the Balancing Authority's Operating Plan(s) after 96 hours.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
1	TBD	NERC Project 2022-03 Energy Assurance – New Standard	New

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2022-03 Energy Assurance with Energy-Constrained Resources | Reliability Standard BAL-008-1

Applicable Standard(s)

- BAL-008-1 – Seasonal Energy Reliability Assessments

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Reliability Coordinator
- Resource Planner

Background

Energy assurance is an increasingly important aspect of a reliable Bulk-Power System but has been inconsistently defined and measured without explicit standards. Project 2022-03 Energy Assurance with Energy-Constrained Resources was initiated to address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Reliability Standard BAL-008-1 – Seasonal Energy Reliability Assessments is focused on the operations planning time horizon.

Effective Date and Phased-In Compliance Dates

The effective dates for proposed Reliability Standard BAL-008-1 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 BAL-008-1

Where approval by an applicable governmental authority is required, Reliability Standard BAL-008-1 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.

Phased-In Compliance Dates

Compliance Date for BAL-008-1 Requirement R1, R2, R3, R4, R5, and R6

Entities shall not be required to comply with Requirements R1 – R6 until 18 months after the effective date of Reliability Standard BAL-008-1.

Compliance Date for BAL-008-1 Requirement R7 and Requirement R8

Initial Balancing Authority review of its seasonal Energy Reliability Assessments process, Scenarios or methods, and Operating Plan(s) is due by the effective date, subsequent reviews due no later than 24 months following the effective date.

Initial Balancing Authority submission to Reliability Coordinator is due by the effective date, subsequent reviews due no later than 24 months following the effective date of a mutually agreed upon schedule.

Periodic reviews and submissions are due no later than 24 months following the effective date.

Compliance Date for BAL-008-1 Requirements R9, R10, R11, R12, and R13

Entities shall not be required to comply with Requirements R9 – R13 until 24 months after the effective date of Reliability Standard BAL-008-1.

Standard Development Timeline

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

Description of Current Draft

This is the 45-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024

Anticipated Actions	Date
45-day formal comment period with additional ballot	May 7 – June 20, 2024
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 13, 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) – Evaluation of the resources to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated evaluation period.

A. Introduction

1. **Title:** Near-term Energy Reliability Assessments
2. **Number:** BAL-007-1
3. **Purpose:** To the risks associated with Energy Emergencies in the near-term time horizon and take appropriate actions to address identified risk. As the Bulk-Power System becomes more reliant upon energy-constrained and variable resources, traditional capacity-based planning methods and strategies might not identify energy-related risks to reliable System operation.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
     - **4.1.2.** Reliability Coordinator
5. **Effective Date:** See Implementation Plan for BAL-007-1.

B. Requirements and Measures

R1. Each Balancing Authority shall document and maintain a process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The near-term ERA must have a duration between five days and six weeks and begin no later than two days after the present operating day.

1.2. The frequency of near-term ERA must be at intervals that ensure all time periods are covered by a near-term ERA.

1.3. The ERA process for near-term ERAs must account for the following:

1.3.1. Forecasted or assumed Demand profiles;

1.3.2. Resource capabilities and operations, including depletion of fuel, variable energy resources (e.g., wind, solar, and hydro), energy transfers between neighboring Balancing Authorities, and electric storage; and

1.3.3. Transmission constraints that limit the ability of generation to deliver their output to load.

1.4. The ERA process for near-term ERAs shall include the rationale for each of the elements in Parts 1.1 through 1.3.

M1. Each Balancing Authority shall have evidence that it documented and maintained a process for conducting near-term ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall document and maintain a set of Scenarios or a method of Scenario creation for use in performing near-term ERAs. Each Scenario or method shall vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible situations. Include a rationale for the Scenarios or method identified. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Forecasted or assumed Demand profiles.

2.2. Resource capabilities and operations, including the following:

2.2.1. The effects of a credible energy supply contingency;

2.2.2. The effects of a credible fuel supply contingency; and

2.2.3. Unplanned generator outages.

2.3. Other Scenarios with a credible or historical risk of occurring based on the best information available at the time of Scenario creation.

M2. Each Balancing Authority shall have evidence that Scenarios or methods were developed and maintained along with a documented rationale in accordance with Requirement R2.

R3. Each Balancing Authority shall document and maintain one or more Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term ERA, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it documented and maintained its Operating Plan(s) in accordance with Requirement R3.

R4. The Balancing Authority shall review and update, if necessary, its near-term ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall have evidence that it reviewed and updated, if necessary, its near-term ERA process, Scenarios or methods, and Operating Plan(s), in accordance with Requirement R4.

R5. Each Balancing Authority shall provide its near-term ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M5. Each Balancing Authority shall have evidence it provided its near-term ERA process, Scenarios, or methods, and Operating Plan(s) documented under Requirement R1 through R3 to its Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule, in accordance with Requirement R5.

R6. Within 60 calendar days of receipt of the information identified in Requirement R5, the Reliability Coordinator shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

6.1. Review each submittal for coordination with other Balancing Authorities' ERA information to avoid risks to Wide Area reliability; and

6.2. Notify each Balancing Authority of the results of its review and if revisions are needed to address reliability risks.

M6. Each Reliability Coordinator shall have evidence that it reviewed each submittal and notified each Balancing Authority of the results of the review in accordance with Requirement R6.

R7. Within 60 calendar days of receipt of the Reliability Coordinator's notice under Requirement R6, each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit the updated information required in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M7. Each Balancing Authority shall have evidence that it addressed any reliability risks identified by its Reliability Coordinator and resubmitted updated information to its Reliability Coordinator in accordance with Requirement R7.

R8. Each Balancing Authority shall perform near-term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M8. Each Balancing Authority shall have evidence that it performed the near-term ERA in accordance with Requirement R8.

R9. If a near-term ERA identifies any of the following forecasted Energy Emergencies listed below, the Balancing Authority shall implement an Operating Plan(s), as documented in Requirement R3. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Forecasted EEA1 circumstances as defined in EOP-011 Attachment 1 Section B
- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B

M9. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) in accordance with Requirement R9.

R10. Each Reliability Coordinator, within 24 hours of receiving a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R8, shall notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators of the forecasted condition(s), and the Balancing Authority's Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M10. Each Reliability Coordinator shall have evidence demonstrating it communicated, within 24 hours from the time of receiving notice of implementation of a Balancing Authority's Operating Plan, with the other Balancing Authorities and Transmission Operators in its Reliability Coordinator area, and neighboring Reliability Coordinators, in accordance with Requirement R10.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Balancing Authority and Reliability Coordinator shall keep data or evidence to show compliance with applicable requirements for six months for near-term time horizon or since the last audit.

   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 Balancing Authority documented an Energy Reliability Assessment process for the near-term time horizon but did not account for one of the elements in Requirement R1 Part 1.1 through Part 1.3. OR The Balancing Authority documented a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon accounting for each of the elements in Requirement R1 Parts 1.1 through 1.3 but failed to maintain it.	The Balancing Authority documented an Energy Reliability Assessment process for the near-term time horizon but did not account for two or more of the elements in Requirement R1 Part 1.1 through Part 1.3. OR The Balancing Authority documented an Energy Reliability Assessment process for the near-term time horizon but did not provide a rationale in accordance with Requirement R1 Part 1.4.	The Balancing Authority failed to document an Energy Reliability Assessment process for the near-term time horizon.
R2.	N/A	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not maintain it. OR The Balancing Authority documented a set of Scenarios or a method of Scenario	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not vary conditions by a sufficient amount to stress the system or include all of the conditions listed in Requirement R2 Parts 2.1 through 2.3.	The Balancing Authority failed to document a set of Scenarios or a method of Scenario creation for use in performing near-term ERAs.

		creation but did not include a rationale for the Scenarios or method identified.		
R3.	N/A	N/A	The Balancing Authority documented and maintained an Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term ERA but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term ERA.
R4.	N/A	N/A	The Balancing Authority reviewed information that contained the near-term ERA process, the ERA scenarios or methods, and Operating Plan(s) but failed to update within 24 months.	The Balancing Authority failed to review and update, if necessary, information that contained the near-term ERA process, the ERA scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.
R5.	N/A	N/A	The Balancing Authority submitted information that contained the near-term ERA process, the ERA scenarios, and Operating Plan(s) but failed to submit to the Reliability Coordinator within 24 months, on a mutually agreed-upon schedule.	The Balancing Authority failed to submit information that contained the near-term ERA process, the ERA scenarios, and Operating Plan(s) to the Reliability Coordinator.
R6.	N/A	The Reliability Coordinator reviewed each submittal for	The Reliability Coordinator reviewed each submittal for	The Reliability Coordinator reviewed each submittal for

		coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but notified one or more Balancing Authority of the results of its review in a time period that was longer than 60 calendar days but less than 90 calendar days.	coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but notified one or more Balancing Authority of the results of its review in a time period that was longer than 90 calendar days but less than 120 calendar days.	coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but failed to notify each Balancing Authority of the results of its review within 120 calendar days.
R7.	N/A	N/A	The Balancing Authority addressed any reliability risks identified by its Reliability Coordinator but failed to resubmit the updated information within 60 calendar days following receipt.	The Balancing Authority failed to address any reliability risks identified by its Reliability Coordinator. OR The Balancing Authority failed to resubmit the updated information required in Requirement R4 to its Reliability Coordinator.
R8.	N/A	N/A	N/A	The Balancing Authority failed to perform a near-term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.
R9.	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a near-term ERA

				identified any of the forecasted conditions in Requirement R8.
R10.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R9 but notified one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 24-25 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R9 but notified one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 25-26 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R9 but notified one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 26-27 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R8 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators within 27 hours or more of receiving notification.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
1	TBD	NERC Project 2022-03 energy assurance new standard.	New

Standard Development Timeline

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

Description of Current Draft

This is the 45-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024

Anticipated Actions	Date
45-day formal comment period with additional ballot	May 7 – June 20, 2024
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 13, 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) ~~-~~– Evaluation of the resources ~~that~~to reliably supply ~~electrical energy~~the Electrical Energy required to serve Demand and ~~ancillary services~~to provide Operating Reserves for the Bulk Power System ~~to reliably meet the expected demand during the~~ throughout the associated ~~time~~evaluation period. ~~ERAs account for the impact of actions that occur sequentially throughout the assessment period, including the depletion and replenishment of finite upstream resources (e.g., fuel).~~

A. Introduction

1. **Title:** Near-term Energy Reliability Assessments
2. **Number:** BAL-007-1
3. **Purpose:** To ~~assess and mitigate~~ the risks ~~of energy emergencies~~associated with Energy Emergencies in the ~~operations planning~~ near-term time horizon ~~by analyzing~~and take appropriate actions to address identified risk. As the ~~expected resource mix availability~~Bulk-Power System becomes more reliant upon energy-constrained and ~~the expected availability of fuel during the study period.~~ variable resources, traditional capacity-based planning methods and strategies might not identify energy-related risks to reliable System operation.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
     - **4.1.2.** Reliability Coordinator
5. **Effective Date:** See Implementation Plan for BAL-007-1.

~~6. **Background:** See Project 2022-03 project page~~

B. Requirements and Measures

R1. Each Balancing Authority shall document and maintain a ~~Reliability Coordinator-reviewed~~process for conducting Energy Reliability ~~Assessment~~Assessments (ERA) ~~process, which shall be reviewed at least annually and updated, if necessary. The ERA process document shall:~~for the near-term time horizon. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.** Identify the frequency and~~ The near-term ERA must have a duration ~~of the ERAs with a corresponding rationale for each following time horizons:~~

~~**1.1.1.** Near-term; and~~

~~**1.2.**~~**1.1.** ~~The end of the near-term assessment period shall be greater than~~ between five days and ~~less than~~ six weeks ~~from the start of the assessment.~~ and begin no later than two days after the present operating day.

~~**1.2.1.1.** Each subsequent near-term assessment period shall partially overlap the previous~~ The frequency of near-term ~~assessment period.~~

~~**1.2.2.** Seasonal;~~

~~**1.3.**~~**1.2.** ~~Seasonal ERAs shall be performed for a minimum of two seasons~~ERA must be at intervals that ~~is representative of seasonal risks for operations~~ensure all time periods are covered by a near-term ERA.

~~**1.3.1.1.** Document a deadline for completing each seasonal ERA based on mitigation options for each seasonal ERA.~~

1.3. ~~Include a~~The ERA process for near-term ERAs must account for the following:

1.3.1. Forecasted or assumed Demand profiles;

1.3.2. Resource capabilities and operations, including depletion of fuel, variable energy resources (e.g., wind, solar, and hydro), energy transfers between neighboring Balancing Authorities, and electric storage; and

1.3.3. Transmission constraints that limit the ability of generation to deliver their output to load.

~~**1.4.**~~ The ERA process for ~~the development of the base case that includes, but is not limited to,~~near-term ERAs shall include the ~~following up-to-date data:~~

~~**1.4.1.** Time series demand;~~

~~**1.4.2.** Demand response, as appropriate;~~

~~**1.4.3.** Generator capability considering known constraints of:~~

~~**1.4.3.1.** Availability, including planned outages, and flexibility;~~

~~**1.4.3.2.** Fuel supply and inventory concerns;~~

~~1.4.3.3. Fuel switching capabilities; and~~

~~1.4.3.4. Environmental constraints.~~

~~1.4.4. Documented energy transfer assumptions; and~~

~~1.4.5. Energy storage capability.~~

~~1.5. Include a documented~~ rationale for each of the ~~base case~~ elements ~~chosen~~ in ~~Requirement R1.2.~~

~~**M1.** Each Balancing Authority shall have evidence of a process document and maintained in accordance with Requirement R1.~~

Parts

~~Each Balancing Authority shall develop, document, and maintain a set of Reliability Coordinator-reviewed ERA scenarios for both the near-term and seasonal time horizons, as follows: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~1.6. Each set of ERA scenarios shall include:~~

~~1.6.1. Projected system load for the interval being studied with system normal (no contingency) conditions;~~

~~1.6.2. Projected system load for the interval being studied with an energy contingency as described in Attachment~~ 1~~;~~

~~1.6.3. Projected system load for the interval being studied with fuel supply contingency as described in Attachment~~ .1~~;~~

~~1.6.4. High load for the interval being studied with system normal (no contingency) conditions;~~

~~1.6.5. High load for the interval being studied with energy contingency as described in Attachment~~ through 1~~;~~

~~1.6.6. High load for the interval being studied with fuel supply contingency as described in Attachment 1; and~~

~~1.6.7. If appropriate for the seasonal time horizon, a scenario(s) with a likely event of occurring within the interval being studied that may include seasonally appropriate historical events, generation specific fuel or energy contingency scenarios, and weather events that are projected to occur if appropriate for the seasonal time horizon only.~~

~~**1.7.**~~**1.4.** ~~The Balancing Authority shall document the rationale for the scenarios identified in Requirement R2.1~~.3.

M1. Each Balancing Authority shall have evidence that it documented and maintained a process for conducting near-term ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall ~~scenarios~~document and maintain a set of Scenarios or a method of Scenario creation for use in performing near-term ERAs. Each Scenario or method shall vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible situations. Include a rationale for the

Scenarios or method identified. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. Forecasted or assumed Demand profiles.

2.2. Resource capabilities and operations, including the following:

2.2.1. The effects of a credible energy supply contingency;

2.2.2. The effects of a credible fuel supply contingency; and

2.2.3. Unplanned generator outages.

2.3. Other Scenarios with a credible or historical risk of occurring based on the best information available at the time of Scenario creation.

M2. Each Balancing Authority shall have evidence that Scenarios or methods were developed and maintained along with a documented rationale ~~and criteria~~ in accordance with Requirement R2. ~~Such evidence could include, but is not limited to, e-mail records or review or revision history to indicate that the scenarios, rationale, and criteria have been documented.~~

~~R2.~~R3. Each Balancing Authority shall ~~develop,~~document and maintain~~, and document~~ one or more Operating Plan(s) to ~~mitigate unacceptable risk(s) associated with~~minimize forecasted Energy Emergencies as identified in the near-term ERA ~~scenario(s) with a likely event of occurring.~~, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it ~~developed, maintained, and~~ documented and maintained its Operating Plan(s) in accordance with Requirement R3~~. Such evidence could include, but is not limited to, a review or revision history to indicate that the Operating Plan(s) have been developed, maintained, and documented~~.

~~R3.~~R4. The Balancing Authority shall ~~submit the following information to its Reliability Coordinator for~~ review ~~on a mutually agreed-upon schedule:~~and update, if necessary, its near-term ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

~~**3.1.** The ERA process;~~

~~**3.2.** The ERA scenarios; and~~

~~**3.3.** Operating Plan(s).~~

M4. Each Balancing Authority shall have evidence that it ~~submitted the information to its Reliability Coordinator on a mutually agreed upon schedule~~reviewed and updated, if necessary, its near-term ERA process, Scenarios or methods, and Operating Plan(s), in accordance with Requirement R4.

R5. Each ~~Such~~Balancing Authority shall provide its near-term ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~M4.~~M5. Each Balancing Authority shall have evidence ~~could include, but is not limited to, e-mail records.~~it provided its near-term ERA process, Scenarios, or methods, and Operating Plan(s) documented under Requirement R1 through R3 to its Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule, in accordance with Requirement R5.

~~R4.~~R6. Within 60 calendar days of receipt of the information identified in Requirement ~~R4~~R5, the Reliability Coordinator shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~4.1.~~6.1. Review each submittal for coordination with other Balancing Authorities' ERA information to avoid risks to Wide Area reliability; and

~~4.2.~~6.2. Notify each Balancing Authority of the results of its review~~,~~ and if ~~the need for~~ revisions ~~is identified,~~are needed to address ~~any~~ reliability risks.

~~M5.~~M6. Each Reliability Coordinator shall have evidence that it reviewed each submittal ~~with other Balancing Authorities' ERA information to avoid risks to Wide Area reliability~~ and ~~notify~~notified each Balancing Authority of the results of the review in accordance with Requirement ~~R5. Such evidence could include, but is not limited to, e-mail records~~R6.

~~R5.~~R7. Within 60 calendar days of receipt of the Reliability Coordinator's notice ~~of the results of the review conducted~~ under Requirement ~~R5~~R6, each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit the updated information required in Requirement R4 to its Reliability Coordinator~~, unless otherwise specified by its Reliability Coordinator.~~. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~M6.~~M7. Each Balancing Authority shall have evidence that it addressed any reliability risks identified by its Reliability Coordinator ~~within 30 calendar days or as specified by~~and resubmitted updated information to its Reliability Coordinator in accordance with Requirement ~~R6. Such evidence could include, but is not limited to, e-mail records.~~ R7.

~~R6.~~R8. Each Balancing Authority shall perform near-term ERAs according to the process documented in Requirement R1 using the ~~scenarios~~Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**M7.**~~**M8.** Each Balancing Authority shall have evidence that it performed the near-term ERA in accordance with Requirement ~~R7. Such evidence could include, but is not limited to, dated ERA results.~~ R8.

~~**R7.** Each Balancing Authority shall determine energy reserve margins calculated for each time step of an ERA scenario according to the following: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**7.1.** For the ERA scenarios identified in Requirement R2.1.1 and Requirement R2.1.4, the energy reserve margin is at least 150% of the largest N-1 Contingency within each Balancing Authority's footprint plus at least 2% of the load forecast for the~~ If a near-term ERA ~~or at least 5% of the load forecast for the seasonal ERA;~~

~~**7.2.** For the ERA scenarios identified in Requirement R2.1.2 and Requirement R2.1.5, the energy reserve margin is at least the larger of 150% of the largest N-1 Contingency within each Balancing Authority's footprint or 2% of the load forecast for the near-term ERA or at least 5% of the load forecast for the seasonal ERA; and~~

~~**7.3.** For the ERA scenarios identified in Requirements R2.1.3, Requirement R2.1.6, and Requirement R2.1.7, the energy reserve margin is at least 125% of the largest N-1 Contingency within each Balancing Authority's footprint.~~

~~**M8.** Each Balancing Authority shall have evidence that it determined an energy reserve margin in accordance with Requirement R8.~~

~~**R8.**~~**R9.** ~~Each Balancing Authority shall compare results of the ERA to the energy reserve margins in Requirement R8 and, if the energy reserve margins are not met~~identifies any of the following forecasted Energy Emergencies listed below, the Balancing Authority shall implement an Operating Plan(s~~) developed~~), as documented in Requirement R3. *[Violation Risk Factor: ~~High~~Medium] [Time Horizon: Operations Planning]*

- Forecasted EEA1 circumstances as defined in EOP-011 Attachment 1 Section B
- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B

M9. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) ~~when the required reserve margin was not met~~ in accordance with Requirement R9.

~~**R9.** Each Balancing Authority shall provide the results of the ERA and the comparison of results from Requirement R9 to its~~ Each Reliability Coordinator ~~under the following conditions: *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*~~

~~**9.1.** The ERA comparison to the energy reserve margin requires implementation of an Operating Plan(s) to mitigate risk~~, within 24 hours ~~for the near-term time horizon or;~~

~~**9.2.** The ERA performed is a seasonal ERA within 14 calendar days or;~~

~~**9.3.** The Reliability Coordinator has requested the results.~~

~~**M10.** Each Balancing Authority shall have evidence that it provided the results of the ERA to its Reliability Coordinator within the criteria in accordance with Requirement R10. Such evidence could include, but is not limited to, e-mail records.~~

R10. ~~Each Reliability Coordinator that receives results of~~ of receiving a ~~near-term ERA and the comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 from~~ notification that a Balancing Authority within its ~~Reliability Coordinator Area~~footprint has implemented an Operating Plan pursuant to Requirement R8, shall notify~~, within 24 hours from the time of receiving notification,~~ other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area~~,~~ and neighboring Reliability Coordinators of the ~~implementation of an~~ forecasted condition(s), and the Balancing Authority's Operating Plan(s). *[Violation Risk Factor: ~~Low~~Medium] [Time Horizon: Operations Planning]*

~~**M11.**~~**M10.** Each Reliability Coordinator ~~will~~shall have ~~and provide upon request,~~ evidence ~~that could include, but is not limited to, operator logs, voice recordings or e-mail records that will be used to determine if the Reliability Coordinator~~demonstrating it communicated, ~~in accordance with Requirement R11,~~ within 24 hours from the time of receiving ~~results~~notice of implementation of a ~~near-term ERA and the comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1 from a~~ Balancing ~~Authority,~~Authority's Operating Plan, with the other Balancing Authorities and Transmission Operators in its Reliability Coordinator area, and neighboring Reliability Coordinators~~ of the implementation of an Operating Plan(s).~~, in accordance with Requirement R10.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Balancing Authority and Reliability Coordinator shall keep data or evidence to show compliance with applicable requirements for six months for near-term time horizon ~~and 18 months for the seasonal time horizon~~ or since the last audit.

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 Balancing Authority documented an Energy Reliability Assessment process for the near-term time horizon but did not account for one of the elements in Requirement R1 Part 1.1 through Part 1.3. OR The Balancing Authority documented a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon accounting for each of the elements in Requirement R1 Parts 1.1 through 1.3 but failed to maintain it~~ at least annually.~~ ~~OR~~ ~~The Balancing Authority documented a Reliability Coordinator-reviewed Energy Reliability Assessment process for the seasonal time~~	The Balancing Authority documented ~~and maintained a Reliability Coordinator-reviewed~~an Energy Reliability Assessment process for the near-term time horizon but did not account for two or more of the elements in Requirement R1 Part 1.1 through Part 1.3. OR The Balancing Authority documented an Energy Reliability Assessment process for the near-term time horizon ~~and seasonal time horizon~~ but ~~failed to include one of the required base case elements under Requirement R1 Part 1.2 or supporting~~ did not provide a rationale~~(s) under~~ in accordance with Requirement R1 Part 1.~~3 for the near-term time horizon or seasonal time horizon.~~4.	The Balancing Authority ~~documented and maintained a Reliability Coordinator-reviewed~~failed to document an Energy Reliability Assessment process for the near-term time horizon~~ and seasonal time horizon but failed to include two or more of the required base case elements under Requirement R1 Part 1.2 or supporting rationale(s) under Requirement R1 Part 1.3 for the near-term time horizon or seasonal time horizon.~~. ~~OR~~ ~~The Balancing Authority failed to document a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon.~~ ~~OR~~ ~~The Balancing Authority failed to document a Reliability Coordinator-reviewed Energy Reliability Assessment process for the seasonal time horizon.~~

		~~horizon but failed to maintain it at least annually~~.		
R2.	N/A	The Balancing Authority ~~developed and~~ documented ~~Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon~~a set of Scenarios or a method of Scenario creation but ~~failed to~~did not maintain ~~them~~it. OR The Balancing Authority ~~developed and~~ documented ~~Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the seasonal time horizon~~a set of Scenarios or a method of Scenario creation but ~~failed to maintain them~~did not include a rationale for the Scenarios or method identified.	The Balancing Authority ~~developed and~~ documented ~~Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon and seasonal time horizons~~a set of Scenarios or a method of Scenario creation but ~~failed~~did not vary conditions by a sufficient amount to stress the system or include ~~one~~all of the ~~scenarios of~~ conditions listed in Requirement R2 ~~Part~~Parts 2.1 ~~or supporting rationales under Requirement R2 Part~~through 2.~~2 for the near-term time horizon or seasonal time horizon~~3.	~~The Balancing Authority developed and documented Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon and seasonal time horizons but failed to include two or more of the scenarios of Requirement R2 Part 2.1 or supporting rationales under Requirement R2 Part 2.2 for the near-term time horizon or seasonal time horizon.~~ ~~OR~~ ~~The Balancing Authority failed to develop or document Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the near-term time horizon.~~ ~~OR~~ ~~The Balancing Authority failed to develop or document Reliability Coordinator-reviewed Energy Reliability Assessment scenarios for the seasonal time horizon.~~ The Balancing Authority failed to document a set of Scenarios or a method of Scenario creation for use in performing near-term ERAs.

R3.	N/A	N/A	~~N/A~~The Balancing Authority documented and maintained an Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term ERA but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to ~~develop~~document an Operating Plan(s) to ~~mitigate risk~~minimize forecasted Energy Emergencies as identified in the ~~Energy Reliability Assessments~~near-term ERA.
R4.	N/A	N/A	The Balancing Authority reviewed information that contained the near-term ERA process, the ERA scenarios or methods, and Operating Plan(s) but failed to update within 24 months.	The Balancing Authority failed to review and update, if necessary, information that contained the near-term ERA process, the ERA scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.
~~R4~~R5.	N/A	N/A	The Balancing Authority submitted information that contained the ~~Energy Reliability Assessment~~near-term ERA process, the ~~Energy Reliability Assessment~~ERA scenarios, and Operating Plan(s) but failed to submit to the Reliability Coordinator within ~~the~~ 24 months, on a	The Balancing Authority failed to submit information that contained the ~~Energy Reliability Assessment~~near-term ERA process, the ~~Energy Reliability Assessment~~ERA scenarios, and Operating Plan(s~~).~~) to the Reliability Coordinator.

			mutually agreed-upon schedule.	
~~R5~~R6.	N/A	~~N/A~~The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but notified one or more Balancing Authority of the results of its review in a time period that was longer than 60 calendar days but less than 90 calendar days.	The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' ~~Energy Reliability Assessment~~near-term ERA information to ~~avoid~~ understand potential reliability risks to Wide Area reliability but ~~failed to notify each~~notified one or more Balancing Authority ~~within 60~~of the results of its review in a time period that was longer than 90 calendar days but less than 120 calendar days.	The Reliability Coordinator ~~failed to review~~ reviewed each submittal for coordination with other Balancing Authorities' ~~Energy Reliability Assessment~~near-term ERA information to ~~avoid~~understand potential reliability risks to Wide Area reliability but failed to notify each Balancing Authority of the results of its review within 120 calendar days.
~~R6~~R7.	N/A	N/A	The Balancing Authority addressed any reliability risks identified by its Reliability Coordinator ~~and resubmitted the updated information required in Requirement R2 to its Reliability Coordinator~~ but failed to resubmit the updated information within 60 calendar days ~~of~~following receipt ~~or as specified by its Reliability Coordinator~~.	The Balancing Authority failed to address any reliability risks identified by its Reliability Coordinator. OR The Balancing Authority failed to resubmit the updated information required in Requirement ~~R2~~R4 to its Reliability Coordinator.
~~R7~~R8.	N/A	N/A	N/A	The Balancing Authority failed to perform ~~Energy Reliability~~

				~~Assessments~~a near-term ERA in accordance with its process documented in Requirement R1 using the ~~scenarios~~Scenarios or methods documented in Requirement R2.
~~**R8**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to determine the energy reserve margins in accordance with Requirements R8 Parts 8.1 through 8.3.~~
R9.	N/A	N/A	N/A	The Balancing Authority ~~compared results of the Energy Reliability Assessment to the energy reserve margins in Requirement R8 but~~ failed to implement an Operating Plan(s) ~~developed in Requirement R3 upon determining the energy reserve margins were not met.~~ ~~OR~~ ~~The Balancing Authority failed to compare results of the Energy Reliability Assessment to the energy reserve margins~~when a near-term ERA identified any of the forecasted conditions in Requirement R8.
~~**R10**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority failed to provide the results of the Energy Reliability Assessment to its Reliability Coordinator when any of~~

				~~the conditions listed in Requirement R10.1 – R10.3 are met.~~
~~R11~~R10.	The Reliability Coordinator received ~~results of~~a notification that a Balancing Authority within its footprint has implemented an ~~Energy Reliability Assessment and comparison of results from Requirement R9~~ Operating Plan pursuant to Requirement ~~R10 Part 10.1~~ R9 but notified ~~other~~one or more Balancing Authorities ~~and~~or Transmission Operators in its Reliability Coordinator Area ~~and~~, or neighboring Reliability Coordinators between 24-25 hours of receiving notification.	The Reliability Coordinator received ~~results of~~a notification that a Balancing Authority within its footprint has implemented an ~~Energy Reliability Assessment and comparison of results from Requirement R9~~ Operating Plan pursuant to Requirement ~~R10 Part 10.1~~ R9 but notified ~~other~~one or more Balancing Authorities ~~and~~or Transmission Operators in its Reliability Coordinator Area ~~and~~, or neighboring Reliability Coordinators between 25-26 hours of receiving notification.	The Reliability Coordinator received ~~results of~~a notification that a Balancing Authority within its footprint has implemented an ~~Energy Reliability Assessment and comparison of results from Requirement R9~~ Operating Plan pursuant to Requirement ~~R10 Part 10.1~~ R9 but notified ~~other~~one or more Balancing Authorities ~~and~~or Transmission Operators in its Reliability Coordinator Area ~~and~~, or neighboring Reliability Coordinators between 26-27 hours of receiving notification.	The Reliability Coordinator received ~~results of~~a notification that a Balancing Authority within its footprint has implemented an ~~Energy Reliability Assessment and comparison of results from Requirement R9~~Operating Plan pursuant to Requirement ~~R10 Part 10.1 but notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators 27 hours or more of receiving notification.~~ ~~OR~~ ~~The Reliability Coordinator received results of an Energy Reliability Assessment and comparison of results from Requirement R9 pursuant to Requirement R10 Part 10.1~~R8 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or ~~one or more~~ neighboring Reliability Coordinators within 27 hours or more of receiving notification.

D. Regional Variances

None.

E. Associated Documents

~~Implementation Plan~~

- Implementation Plan
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
~~Version~~ 1	TBD	~~Drafted by~~NERC Project 2022-03 ~~SDT~~energy assurance new standard.	New

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Implementation Plan

Project 2022-03 Energy Assurance with Energy-Constrained Resources | Reliability Standard BAL-007-1

Applicable Standard(s)

- BAL-007-1 – Near-term Energy Reliability Assessments

Requested Retirement(s)

- None

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Reliability Coordinator

Terms in the NERC Glossary of Terms

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

Proposed New Definition(s):

Energy Reliability Assessment:	Evaluation of the resources to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated evaluation period.

Background

Energy assurance is an increasingly important aspect of a reliable Bulk-Power System (BPS) but has been inconsistently defined and measured without explicit standards. Project 2022-03 Energy Assurance with Energy-Constrained Resources was initiated to address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Reliability Standard BAL-007-1 – Energy Reliability Assessments is focused on the operations planning time horizon.

Effective Date and Phased-In Compliance Dates

The effective dates for proposed Reliability Standard BAL-007-1 and NERC Glossary term Energy Reliability Assessment 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.

BAL-007-1 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard BAL-007-1 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.

Phased-In Compliance Dates

Compliance Date for BAL-007-1 Requirements R1, R2, and R3

Entities shall not be required to comply with Requirements R1 – R3 until 18 months after the effective date of Reliability Standard BAL-007-1.

Compliance Date for BAL-007-1 Requirements R4 and R5

Initial Balancing Authority review of its near-term Energy Reliability Assessments process, Scenarios or methods, and Operating Plan(s) is due by the effective date, subsequent reviews due no later than 24 months following the effective date.

Initial Balancing Authority submission to Reliability Coordinator is due by the effective date, subsequent reviews due no later than 24 months following the effective date on a mutually agreed upon schedule.

Periodic reviews and submissions are due no later than 24 months following the effective date.

Compliance Date for BAL-007-1 Requirements R6, R7, R8, R9, and R10

Entities shall not be required to comply with Requirements R6 – R10 until 24 months after the effective date of Reliability Standard BAL-007-1.

Definition

Where approval by an applicable governmental authority is required, the definition of Energy Reliability Assessment 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 Reliability Standard BAL-007-1, 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 that Reliability Standard BAL-007-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Unofficial Comment Form

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on draft two of **BAL-007-1 – Near-term Energy Reliability Assessments** and draft one of **BAL-008-1– Seasonal Energy Reliability Assessments** by **8 p.m. Eastern, Thursday, June 20, 2024.**

Additional information is available on the project page. If you have questions, contact Standards Developer, Jordan Mallory (via email).

Background Information

Project 2022-03 currently has two assigned Standard Authorization Requests (SARs) that seek to enhance reliability by requiring entities to perform Energy Reliability Assessments (ERAs) to evaluate energy assurance and develop Corrective Action Plan(s), Operating Plan(s), or other mitigating actions to address identified risks to each respective time horizon:

- Operations/operational planning time horizon (Operations SAR)
- Planning time horizon (Planning SAR)

The proposed new Reliability Standards are based on the Operations SAR. The planning time horizon SAR will be addressed at a later date.

The Standards Committee (SC) accepted the revised SARs at its January 25, 2023, meeting. At the same meeting, the SC authorized drafting of the Reliability Standard(s) identified in the SARs. Since that time, the team has conducted several meetings, both remote and in-person, and posted a draft of a new standard for informal comment to solicit feedback and completed one initial comment and ballot period for BAL-007-1.

Summary of changes Overview

Based on industry feedback, the standard drafting team (SDT) modified the ERA definition. In addition, determined that near-term ERAs and seasonal ERAs would be better suited in separate standards. The team kept near-term ERAs in BAL-007-1 and created a new BAL-008-1 to address seasonal ERAs. The purpose of this change was to make each requirement clearer about what applied to each standard and allow for two ERAs to be better distinguished. Please refer to the BAL-007-1 and BAL-008-1 Technical Rationale document for additional justification and information regarding requirements within the proposed standards.

As a reminder, the proposed definition is not balloted separately but is being balloted via the BAL-007-1 standard. As such, when voting on the standard, ballot body participants will also be voting on the proposed definition used in the standard.

Questions

BAL-007-1 Near-term ERAs

1. The standards drafting team (SDT) modified the Energy Reliability Assessment (ERA) definition based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification.

   ☐ Yes
   ☐ No

   Comments:

2. Based on industry feedback, the SDT updated Requirement R1 to clarify what near-term ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No

   Comments:

3. The SDT updated Requirements R2 through Requirement R8 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No

   Comments:

4. The SDT proposes entities use forecasted Demand profiles for the time interval under study for the BAL-007 assessment. The SDT's goal is to align measures for ERAs with those used for EOP-011. Actions taken as part of a BAL-007 Operating Plan should be targeted to minimize any Energy Emergency events. Do you agree with the updated proposed language in Requirement R8? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No

   Comments:

5. The SDT updated Requirement R9 based on industry feedback. Do you agree with the updated proposed language in Requirement R9? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No

   Comments:

6. The SDT updated the implementation plan to allow for 18 months for Requirements R1 through R3 and 24 months for Requirements R4 through Requirement R10 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No

   Comments:

7. The SDT believes that fuel data information needed to address BAL-007-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No
   Comments:

8. The SDT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

   ☐ Yes
   ☐ No
   Comments:

9. Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

   Comments:

BAL-008-1 Seasonal ERAs

10. The SDT drafted BA-008-1 Requirement R1 to clarify what seasonal ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

    ☐ Yes
    ☐ No

    Comments:

11. The SDT drafted BAL-008-1 Requirements R2 through R13 based on industry feedback regarding seasonal ERAs. Do you agree with the proposed requirements? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

    ☐ Yes
    ☐ No

    Comments:

12. The SDT drafted the BAL-008-1 implementation plan to allow for 18 months for Requirements R1 through R6 and 24 months for Requirements R7- R13 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

    ☐ Yes
    ☐ No

    Comments:

13. The SDT believes that fuel data information needed to address BAL-008-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

    ☐ Yes
    ☐ No

    Comments:

14. The SDT proposes that the newly proposed BAL-008-1 meets the Standards Authorization Request 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:

15. Provide any BAL-008-1 additional comments for the SDT to consider, if desired.

    Comments:

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Technical Rationale

Project 2022-03 Energy Assurance with Energy-Constrained Resources
Reliability Standard BAL-007-1 | May 2024

BAL-007-1– Near-term Energy Reliability Assessments

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard BAL-007-1. It provides stakeholders and the Electric Reliability Organization (ERO) Enterprise with an understanding of the technical requirements in the Reliability Standards. This Technical Rationale and Justification for BAL-007-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Updates to this document include the Project 2022-03 Energy Assurance with Energy-Constrained Resources Drafting Team's (DT's) intent in drafting new requirements.

Overview

Inconsistent output from variable energy resources, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the Bulk Power System (BPS) needed to serve electrical demand, maintain sufficient Operating Reserve, and ensure the reliable operation of the BPS. As part of ongoing operations planning, many entities have started incorporating some limited assessments of energy reliability into studies that produce key metrics; however, there is inconsistency among entities on how the assessments are performed. To achieve the level of consistency needed across the industry, to reliably predict the energy needed to serve the load, energy reliability assessments for the operations time horizon and the minimization of identified risks are mandated and codified in these new standards. Project 2022-03 proposes two new Reliability Standards, BAL-007-1 and BAL-008-1, and the Energy Reliability Assessment (ERA) definition. The purpose of the proposed Reliability Standard BAL-007-1 is to identify and minimize the risks of forecasted Energy Emergencies in the operations planning time horizon by analyzing the expected resource mix availability and the expected availability of fuel.

Rationale for BAL-007-1

As the BPS becomes more reliant upon energy constrained and variable resources, traditional capacity-based planning methods and strategies are being stretched and potentially do not identify energy-related risks to reliably operate and maintain the system. BAL-007-1 is being proposed as a step toward reducing these potential risks and to begin the transition to energy-based planning methods and strategies that incorporate critical time-based variables that are not captured in capacity-based processes. BAL-007-1 is intended to provide Balancing Authorities (BAs) and Reliability Coordinators (RCs) with the tools necessary to successfully navigate increasingly energy-constrained and variable system operations. BAL-007-1 Operating Plan(s), which are not intended to replace or supersede TOP-002 and EOP-011 Operating Plans, are intended to provide a list of actions over a longer-term/earlier time period that can reduce the severity of or fully mitigate the need to implement TOP-002 and/or EOP-011 plans.

The new Reliability Standards can be separated into three basic activities:

- Developing and documenting an ERA process, Scenarios or a method for creating them, and Operating Plans (Requirements 1-7).
- Performing ERAs and comparing to forecasted Energy Emergency circumstances (Requirement 8).
- If forecasted Energy Emergency circumstances are identified, implementing Operating Plan(s) to minimize energy reliability risks and communicating that implementation (Requirements 9-10).

The purpose of the standard is to assess energy risk in the Operations Planning time horizon, determine if the identified risks are acceptable, and take actions to minimize the impacts. It should be noted that the standard offers the flexibility to allow for either a deterministic or probabilistic implementation of an ERA process. This has been left up to the BA to determine which method is right for their region. This standard improves reliability through identifying energy risks earlier and being able to implement longer lead time activities to mitigate those risks.

The diagram below gives an overview of the process with actions and communication between entities outlined.

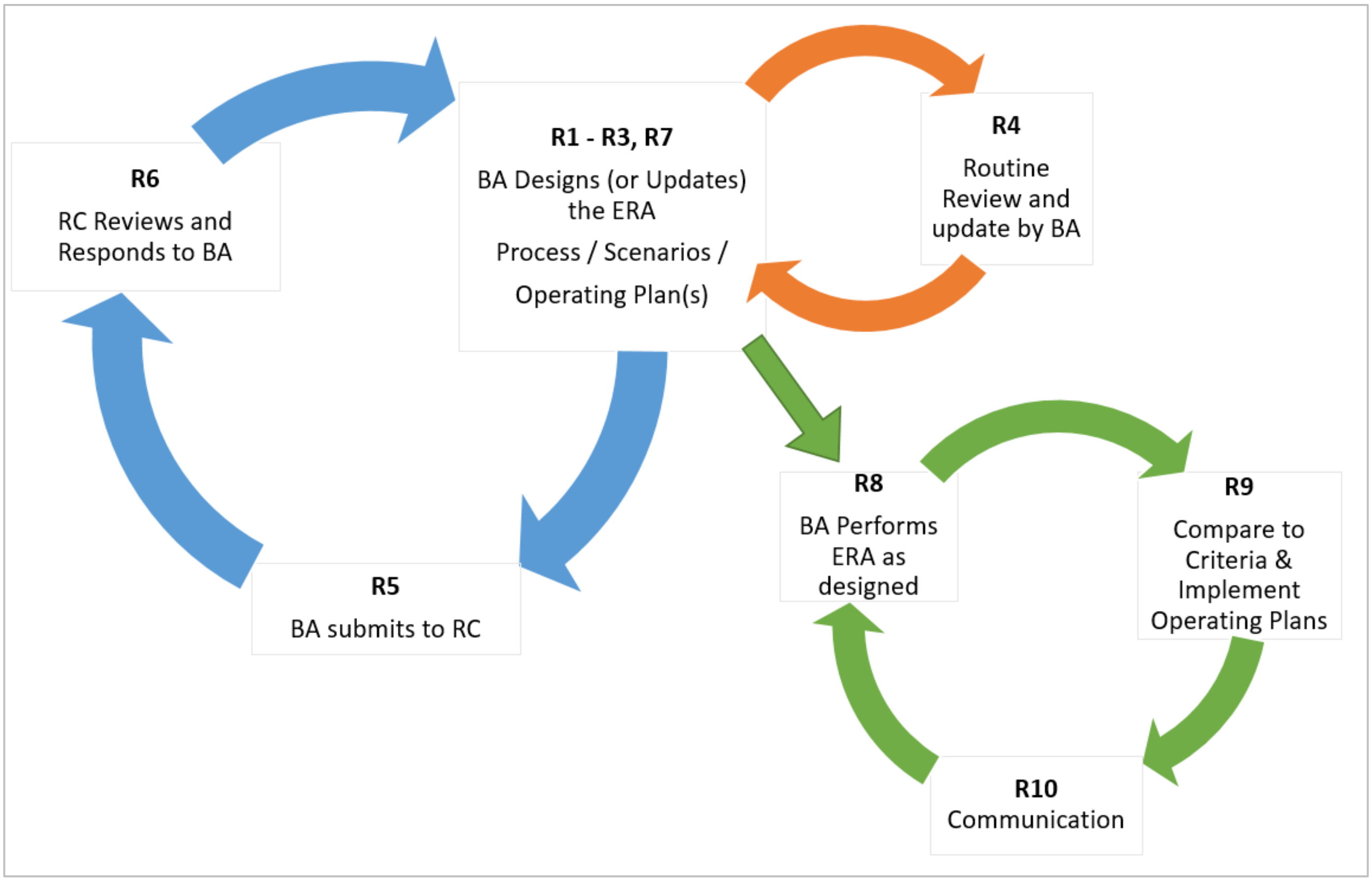

Figure 1. Process Diagram of ERA Requirements

Relationship to Other Standards

While the proposed standard has similarities to other standards, especially TOP-001, TOP-002, and EOP-011 standards, the proposed standard addresses reliability risks due to gaps in the existing reliability standards by focusing on different time horizons than current standards and energy risks which are not clearly addressed. In many cases, the language is intentionally similar to language in those requirements but applicable to different time horizons. The BAL-007-1 standard looks at a near-term time horizon which is longer than other operations planning assessment requirements. In terms of addressing energy risks, BAL-007-1 more clearly outlines the assessment requirements to look at energy over an assessment period rather than capacity assessments generally used to comply with current standards.

TOP-001 and TOP-002 provide requirements for assessments and Operating Plans in real-time and operations planning time horizons, but their requirements are limited to, at most, the next day which limits the options that Balancing Authorities may take to respond. BAL-007-1's proposed language extends this outlook to at least greater than five days and up to six weeks ahead, so BAs have time to implement mitigation actions with longer lead times (e.g., reschedule outages, conserve consumable fuel, source additional fuel) and have better situational awareness of potential reliability risks.

TOP-002, EOP-011, and BAL-007-1 all require Operating Plans to minimize or mitigate reliability risks, but they would likely differ in what actions that a BA would deem appropriate to be included in each. Since BAL-007-1 is assessing a longer time horizon, the projected conditions are more uncertain, and the Operating Plans developed should reflect that. Instead of identifying specific actions that must be taken, the Operating Plans under BAL-007-1 are expected to have more general processes than Operating Plans in TOP-002. BAL-007-1 Operating Plans are not intended to replace TOP-002 and EOP-011 Operating Plans but to identify additional actions that can be implemented when potential risks are identified with a longer lead time. The goal of these longer-term Operating Plans is to reduce the likelihood or the severity of an actual Energy Emergency occurring, which would require an EOP-011 Operating Plan. Actions that are taken as outlined in the BAL-007-1 Operating Plans would then lead into the real-time and day-ahead Operating Plans, through the establishment of more favorable initial conditions, rather than overlapping them. An example timeline of how BAL-007-1 and EOP-011 would interact is below when the BAL-002 associated Operating Plans are not sufficient to avoid an Energy Emergency. Ideally, the longer-term Operating Plan(s) would result in the EOP-011 Operating Plan not being needed but if an Energy Emergency still occurs, the Operating Plans should have reduced the severity of the Energy Emergency.

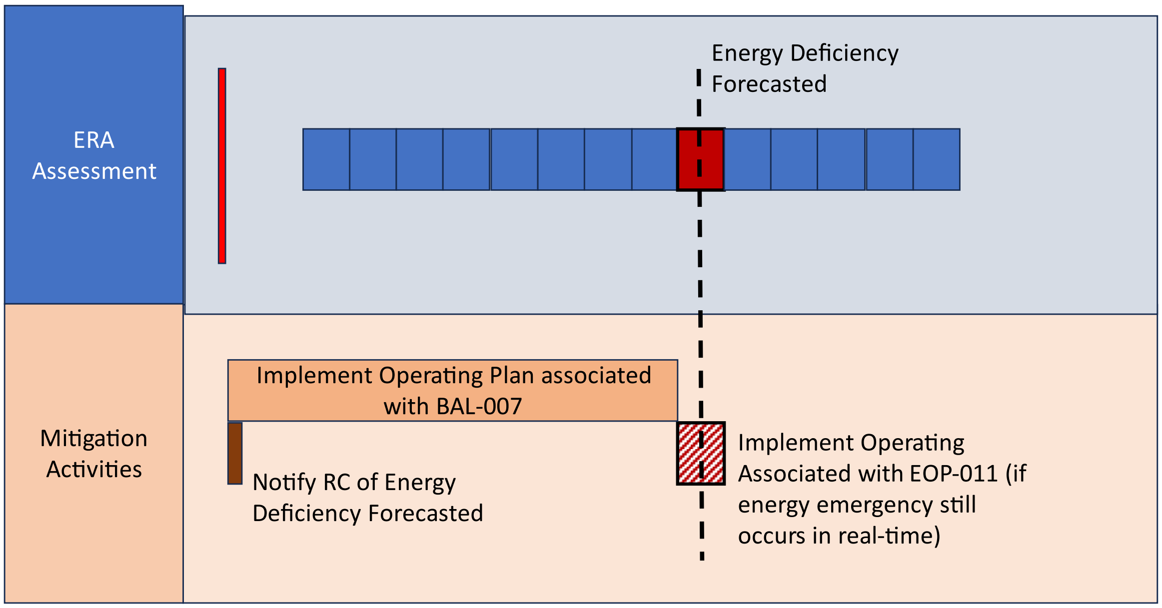

Figure 2. Timeline of ERA performance and Operating Plan Implementation if the forecasted energy deficiency is not fully mitigated when EOP-011 Operating Plan is still required.

Additionally, the BAL-007-1 assessments require considering energy risk which can only be performed by looking at an assessment over a time period with multiple time steps and considering the depletion of stored energy and the production from just-in-time, variable energy resources. While EOP-011 Requirement R2 includes “Energy Emergencies” as a risk that Operating Plans must address, these assessments have generally been performed as capacity assessments, or potentially a series of capacity assessments in succession, which do not necessarily include variable energy and fuel risk, especially over a longer period of time. BAL-007-1 explicitly requires including these elements in an assessment and set criteria regarding when risks need to be addressed through Operating Plans.

The Balancing Authority (BA) may require additional data from other entities and should consider this when documenting the process. While BAL-007-1 does not require other entities to provide necessary data, TOP-003 requires the BA to “maintain a documented specification for the data necessary for it to perform its analysis functions…” in Requirement R2 and requires the other entities to provide the data in Requirement R5. Since these TOP-003 Requirements broadly give the BA the ability to request data “to perform its analysis functions” and does not limit that to assessments to a specific time horizon, TOP-003 should provide a mechanism for BAs to request and receive the necessary data for ERAs.

Proposed New Terms:

Energy Reliability Assessment (ERA)
Evaluation of the resources to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated evaluation period.

Rationale
The ERA definition was added to allow for Energy Reliability Assessments to be performed in different time horizons using similar processes prescribed by NERC standards, but also through other processes while maintaining a consistent understanding of what an ERA is. These assessments are intended to look at the wide variety of resources available to serve load's energy requirements not only in the near-term but also in other time horizons including the long-term planning horizon. ERAs go beyond the existing scope of the capacity assessments that have traditionally been performed to look more closely at energy needs.

Requirements:

Requirement R1
Requirement R1 identifies the basis for defining what an ERA is. Time horizons and basic input assumptions in the near-term are specifically designed by each BA according to their risks and their supply and demand profiles. Because of differences in risks and in supply and demand profiles between regions, rather than requiring a set of prescriptive elements to assess, each BA is provided with minimum assessment requirements which they will use to define the scope for performing their ERAs and document a rationale.

Balancing Authorities may perform the required ERAs for just their area or a group of BAs may jointly perform their ERAs. Should a deficiency be identified, the BAs, regardless of whether they performed their assessment jointly or individually, can utilize their energy reserve sharing group of available resources. The goal of the ERA is to determine if sufficient energy is available. A review of the energy reserve sharing group should be performed to verify that it is sufficient to meet the groups combined needs. Again, the goal of the ERAs is to improve reliability for the system and the load.

The ERA process will include definitions for a duration, frequency, how they account for the necessary parameters to determine energy needs, what resources can be used, and when to meet them. The duration can be within a specified range for the near-term assessments as identified by the BA, again providing for regional flexibility. It is understood that specific regions will have a different set of concerns and risks. Some regions have a resource mix that may include a large percentage of variable energy resources. Others may have risks due to either a non-firm fuel supply issue (e.g. non-firm gas supply) or non-firm transmission service due to system congestion. For example, a region that is heavily dependent on resources requiring more maintenance may need to look further into the future to manage these outages to confirm that there will be sufficient energy available. An entity with more variable energy resources with possible congestion may need to look more closely at the weather forecast and review their energy supply mix more frequently. The process is intended to ensure that as changes in the resource mix or demand profiles become reality, they are captured appropriately and intentionally. New resource types are being introduced into the power system more frequently compared to years past, a trend that is expected to continue. Each new resource type comes with subtleties of how they perform and operate that may require a change to the way resources are portrayed in an ERA. Forecasted weather events that occur within a BA's footprint (e.g., droughts, storms, calm and cloudy stretches) will also change the expected resource availability when an ERA is performed. Near-term ERAs are intended to be performed on a routine basis and look at the time period that covers the next several days to weeks, with an emphasis on beginning the day after the next day (i.e., after the end of the current TOP-002 associated Operating Plan).

Demand profiles will be determined by the BA as well. Entities will have a number of items to consider prior to determining their Demand profile. It is up to the BA to determine exactly how Demand will be modeled, including considerations for a variety of how demand response is treated. A BA may choose to include market based or dispatchable demand response but it is recommended that other forms of demand response should not be included, which would leave load reduction options as a last resort (e.g., voltage reduction, load cycling, etc.). Each BA will need to identify what their type of demand response is and when, if ever, to consider it. Load shed should only be identified as part of a plan if this is the last resort.

ERAs must ensure that every period of time is assessed. For example, performing a two-week long ERA every two weeks would meet the near-term requirement. The determination of how long to study will be based on several factors such as system or generation outage recall timing, accuracy of forecast information beyond the next few days, or lead time for fuel replenishment. A minimum amount of information that must be included in every ERA is identified in the standard. Based on the region of the BA performing the ERA, more information might be needed than for others. The standard does not contain an all-inclusive list. If other parameters are necessary for a BA to fully model the energy landscape for the ERA, they should be included and documented with a rationale for inclusion and selection.

Requirement R2

Requirement R2 outlines a minimum set of Scenarios that must be included in an ERA. The intent is to provide a mechanism for each BA to gauge how close to an Energy Emergency they may be in certain situations. Credibility of the Scenarios is for the BA to define and document.

There are four types of scenarios, three for supply and one demand, that can be varied independently or in combination with each other. At least one parameter should be varied enough to stress the system to determine if the (remaining) available resources are robust enough to meet the Demand and Operating Reserves. A possible load Scenario could be raising Demand from a 50/50 profile to a higher profile, such as a 90/10 or maximum load scenario, to measure the impact to the system and determine if shortfalls are detected. There are three supply side Scenarios to be studied. The first is a credible energy contingency that removes one of the largest energy resources from the base case and runs it again. Large energy resources may be the same as large capacity resources, but not necessarily in all cases. The second supply Scenario removes a credible set of resources that are supplied by the same fuel supply. This is traditionally thought of as natural gas supplying multiple generating stations and may be just that, but could also be a set of wind turbines that are closely situated where a storm could render them unavailable for a period of time or solar panels that are covered by snow or smoke from a fire. The final scenario is a generator outage for an unplanned outage. Regardless of the chosen energy and fuel Scenarios, it is up to the BA to determine which resource or set of resources are included in the ERA. The choices by the BA in Scenarios should be documented and identified in their rationale.

In addition to the above defined scenarios, Requirement R2 specifies the consideration of "Other Scenarios with a credible or historical risk of occurring based on the best information available at the time of Scenario creation." An example of these Scenarios in a near-term ERA includes a Scenario that stressed the System such as the impacts of a winter storm that occurred within the previous five years. It is credible that a similar storm could occur during near term ERAs that cover this season.

Requirement R3

The near-term time horizon specified in BAL-007-1 offers a different vantage point than next day and real-time assessments. The actions that a BA can take due to an identified risk of an energy shortfall are different when identified days to weeks earlier than if waiting for a next day or real-time assessment. An example of actions that could be taken based on the results of a near-term assessment that may not be available for a next day or real-time assessment include requesting for energy resources or transmission facilities to return from maintenance or construction outages earlier than planned or to postpone a planned outage. If an entity were to wait for the next day studies to identify a risk, fewer options for the BA to avoid an energy risk in real time would be available.

Requirement R3 requires BAs to develop Operating Plans prior to forecasting Energy Emergencies through ERAs to minimize their effects. These Operating Plans are developed so that in the event that an ERA shows that a BA may have insufficient energy, they will have an Operating Plan ready to implement, per Requirement R3, that has been reviewed and updated before system conditions are unfavorable and be ready for later implementation. Operating Plans are expected to include actions that can be performed by the BA within the time horizon for which the ERA is designed, near-term. The actions that BAs may include in Operating Plans will also provide information to the BA regarding how long the assessment period of the ERA might need to be (Requirement R1) such that they can have time to accomplish the actions identified. For example, if actions that could minimize potential Energy Emergencies take two weeks to accomplish, the ERA should be looking at least two to three weeks into the future.

As discussed in the Relationship to other Standards section, the Operating Plans developed based on this requirement are not intended to supersede Operating Plans associated with TOP and EOP standards but to complement them and include actions that will reduce the likelihood or severity of an energy deficiency occurring in real-time. To that end, the BA develops an appropriate Operating Plan for a forecasted Energy Emergency that is identified by an ERA. Depending if the ERA is completed weeks or days prior to the Energy Emergency, the BA decides on suitable plans to reduce the impact. Since the Operating Plans are being implemented based on assessments looking days to weeks ahead, considering the associated uncertainty of the results, BAs may decide to exclude actions in the BAL-007-1 Operating Plans which would only need to occur much closer to the projected event or only plan to implement those actions if the projected conditions of the ERA appear that they will still occur. For example, an Operating Plan may include increasing the frequency of performing ERAs in order to monitor whether the forecasted Energy Emergency is more or less likely as the uncertainty of input data to the assessment decreases and other actions in the Operating Plan have been implemented. Again, the goal of performing an ERA is to identify those times when a forecasted Energy Emergency might occur. The developed Operating Plan should have steps that can be taken to minimize, or mitigate, the forecasted Energy Emergency.

The ERA Operating Plans should be designed to be adaptable to unfolding conditions and proactive enough to possibly avoid an energy shortage through advanced actions. As an example, to illustrate the Operating Plan uses, when an ERA is performed two weeks ahead of a calculated shortfall then potential actions have a two-week timeline to perform the appropriate action plans as well as monitor if the identified risk conditions have changed. For instance, if the results from a two-week duration ERA during an extremely cold period determines an Energy Emergency may occur, the BA's Operating Plan could include the following actions:

- Survey scheduled outage system to determine if any generation currently out for maintenance can return earlier than planned.
- Survey if any transmission outages affect either generation deliverability or import capability. If yes, can they be returned to service prior to the forecasted Energy Emergency.
- Survey if generation and transmission scheduled to go out can defer their outages until after the event.
- Notify RC and relevant entities of the projected risk (e.g., relevant government authorities for assessing the need and strategy for public appeals or other BAs to account for expected imports or exports).
- Make sure all energy storage units can be fully available to help mitigate energy shortfalls.
- Increase frequency of performance of ERAs, including possibly daily, and assess energy availability and have Operating Plan actions conditional on the level of risk.
- If ERA results still indicate unacceptable risk of energy deficiency two days prior to projected event, instruct thermal plants to warm up leading up to event to avoid outages due to ice formation and cold-start issues.

Ideally, these actions will minimize or prevent an Energy Emergency that might occur in real-time. However, if the Energy Emergency still occurs, these actions should reduce the energy deficiency and prepare the BAs to implement an emergency Operating Plan. This scenario is intended only to be one simple illustrative example that does not reflect all potential Operating Plan actions or actions that BAs in all regions can do.

While scheduling increased imports can be a part of the Operating Plan, it is imperative that the BA verify that the resources they have scheduled will continue to be there to solve their Energy Emergency. It should not be assumed that once imports are scheduled, this energy is a firm supply. Both BAs may be impacted by the event causing an Energy Emergency for both areas. The supplying entity may not be able to honor their agreement to provide this energy.

Requirement R4

Requirement R4 requires that the BA review their process, Scenarios, and Operating Plans, in Requirements R1 through R3, to determine if any changes are needed. The BA shall review this documentation no less than once every 24 months. Due diligence during the design and review phases by the BA is required to identify potential risks and possible actions that could minimize those risks that would lead to an energy shortfall in the near-term timeframe.

Requirement R5

Requirement R5 provides a channel of communication between a BA and their associated RC. Requirement R5 is simply a BA providing their ERA process documentation, as defined by R1, R2, and R3, to the RC. The BA and the RC shall develop a mutually agreed-upon schedule, no greater than every 24 months. Depending on the RC, this may be requested more frequently. The designed process, along with the base condition, Scenarios or method for their creation, and Operating Plan(s) are all part of the package that needs to be reviewed.

Requirement R6

Providing ERA information to the RC under Requirement R5 is paired with this Requirement for the RC to review each package within 60 days of receipt. The RC review is intended to identify risks that may not have been considered for Wide Area reliability and ensure all identified risks are communicated to the BA. Coordination is required to ensure that there are no conflicting assumptions between BAs. Once a review is complete, the RC notifies the BA, and any necessary changes occur within Requirement R6. For example, an assumption by two BAs, sharing a common transmission interface, each identifying an import condition during the same time period would result in an infeasible allocation of energy resources and would trigger an RC notification. The RC review provides additional reliability benefits, by comparing the BA's ERA information to that of other BAs, allowing for identification and clarification of discrepancies and/or opportunities for enhancements to strengthen the contents of a BA's ERA package.

It is the intention for implementing BAL-007-1 that the routine review of each ERA by the RC can be accomplished within the required timeframe. However, it is understood that when ERAs are newly designed, along with Scenarios and Operating Plans, that more time will be needed by the RC to perform a thorough review. For this reason, implementation of Requirements 4 through 10 have an additional six months.

Requirement R7

Requirement R7 is the third part of the communication between the RC and BA where the BA is required to address any issues identified by the RC and resubmit their ERA process, Scenarios or the method for creation, and Operating Plan(s). This requirement ensures the closing of the communication loop and documentation that the RC's review comments generated in Requirement R6 are addressed. Requiring the BA to address and document responses to feedback generated by the RC review ensures that the reliability benefits described in Requirement R6 of an RC's cross-comparison of packages from multiple BAs are enshrined and potential Wide Area reliability risks are minimized or avoided.

Requirement R8
Requirement R8 specifies that the near-term ERA be performed as designed, reviewed, and approved.

Requirement R9
Requirement R9 specifies what constitutes three different circumstances that identify a forecasted Energy Emergency. The forecasted Energy Emergency conditions are intended to be a clear threshold where the ERA results identify levels of impending risk and require actions be performed to minimize the potential they will occur. The definitions of what constitutes a forecasted Energy Emergency are in alignment with the Energy Emergency Alert (EEA) definitions in EOP-011. The difference for BAL-007-1 is that instead of being a real-time Energy Emergency, these would be forecasted events. The goal here is that if an Energy Emergency is forecasted in an ERA, the associated Operating Plan will have targeted steps to help minimize the forecasted Energy Emergency before it gets to be an Energy Emergency in the next day and real-time timeframes.

There are three EEA levels and three levels of forecasted Energy Emergencies. The criteria for forecasted Energy Emergency apply also to Scenarios identified in Requirement 2 and studied in Requirement 8. This level of granularity allows for the BA to design an Operating Plan that fits the specific situation. Given Scenarios may be expected to enter the lower levels of an Energy Emergency, and the actions in an Operating Plan should be appropriate for that combination.

Finally, by leveraging the existing terms used in EOP-011 for EEA, clear and well-understood definitions are already in place which require little to no training, beyond the advanced timing associated with BAL-007-1. BAs have existing interpretations of how they respond when nearing or entering an EEA and the existing interpretations are expected to be used, including those that involve interaction with Reserve Sharing Groups.

Requirement R10
After receipt of notification from the BA that an Operating Plan is being implemented, Requirement 10 requires communication between the RC and Transmission Operators, other BAs within their footprint, and neighboring RCs. The time requirements for the notifications for near-term ERAs is 24 hours. The purpose of these communication requirements is to provide situational awareness from the RC to other entities that may be impacted by a forecasted Energy Emergency in a BA. With this information, other BAs and Transmission Operators can better plan for their own reliability risk, especially if they expected to rely on neighboring BAs for imports. Additionally, the RC receiving this information from multiple BAs allows the RC to have a wide area view of the energy risk and provide any insight they may have to minimize it. This communication is required only after the RC receives notification, which is one of the provisions required in the development of Operating Plans in Requirement R3.

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Technical Rationale

Project 2022-03 Energy Assurance with Energy-Constrained Resources
Reliability Standard BAL-008-1 | May 2024

BAL-008-1– Seasonal Energy Reliability Assessments

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

Updates to this document include the Project 2022-03 Energy Assurance with Energy-Constrained Resources Standards Drafting Team's (SDT's) intent in drafting new requirements.

Overview
Inconsistent output from variable energy resources, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the Bulk Power System (BPS) needed to serve electrical Demand, maintain sufficient Operating Reserve, and ensure the reliable operation of the BPS. As part of ongoing operations planning, many entities have started incorporating some limited assessments of energy reliability into studies that produce key metrics; however, there is inconsistency among entities on how the assessments are performed. To achieve the level of consistency needed across the industry, to reliably predict the energy needed to serve the load, Energy Reliability Assessments for the operations time horizon and the minimization of identified risks are mandated and codified in these new standards. Project 2022-03 proposes two new Reliability Standards, BAL-007-1 and BAL-008-1, and the Energy Reliability Assessment (ERA) definition. The purpose of the proposed Reliability Standard BAL-008-1 is to identify and minimize the risks of forecasted Energy Emergencies in the operations planning time horizon by analyzing the expected resource mix availability and the expected availability of fuel. Seasonal ERAs provide additional time for actions beyond that provided with only a near-term ERA.

Rationale for BAL-008-1
As the BPS becomes more reliant upon energy constrained and variable resources, traditional capacity-based planning methods and strategies are being stretched and potentially do not identify energy-related risks to reliably operate and maintain the system. BAL-008-1 is being proposed as a step toward continuing to reduce these potential risks and with the transition to energy-based planning methods and strategies that incorporate critical time-based variables that are not captured in capacity-based processes. BAL-008-1 is intended to provide Balancing Authorities (BAs) and Reliability Coordinator (RCs) with the tools necessary to successfully navigate increasingly energy constrained and variable system operations. BAL-008-1 Operating Plans, while not intended to replace or supersede BAL-007, TOP-002 and/or EOP-011 Operating Plans, are intended to provide a list of actions implementable over a longer-term/earlier time period that can reduce the severity of or fully mitigate the need to implement BAL-007, TOP-002 and/or EOP-011 plans.

The new Reliability Standard can be separated into three basic activities:

- Developing and documenting an ERA process, Scenarios or a method for creating them, and Operating Plans (Requirements 1-3, 7-10)
- Requesting any needed data from the Resource Planner (Requirements 4-6);
- Performing ERAs and comparing to the levels of a forecasted Energy Emergency (Requirements 11-12); and
- If a forecasted Energy Emergency is identified, implementing Operating Plan(s) to minimize energy reliability risks (Requirements 13)

The purpose of these standards are to assess energy risk in the Operations Planning time horizon, determine if the identified risks are acceptable, and if not acceptable take actions to minimize. It should be noted that the standard offers the flexibility to allow for either a deterministic or probabilistic implementation of an ERA process. This has been left up to the BA to determine which method is right for their region. This standard improves reliability through identifying energy risks earlier and being able to implement longer lead time activities to mitigate those risks.

The diagram below gives an overview of the process with actions and communication between entities outlined.

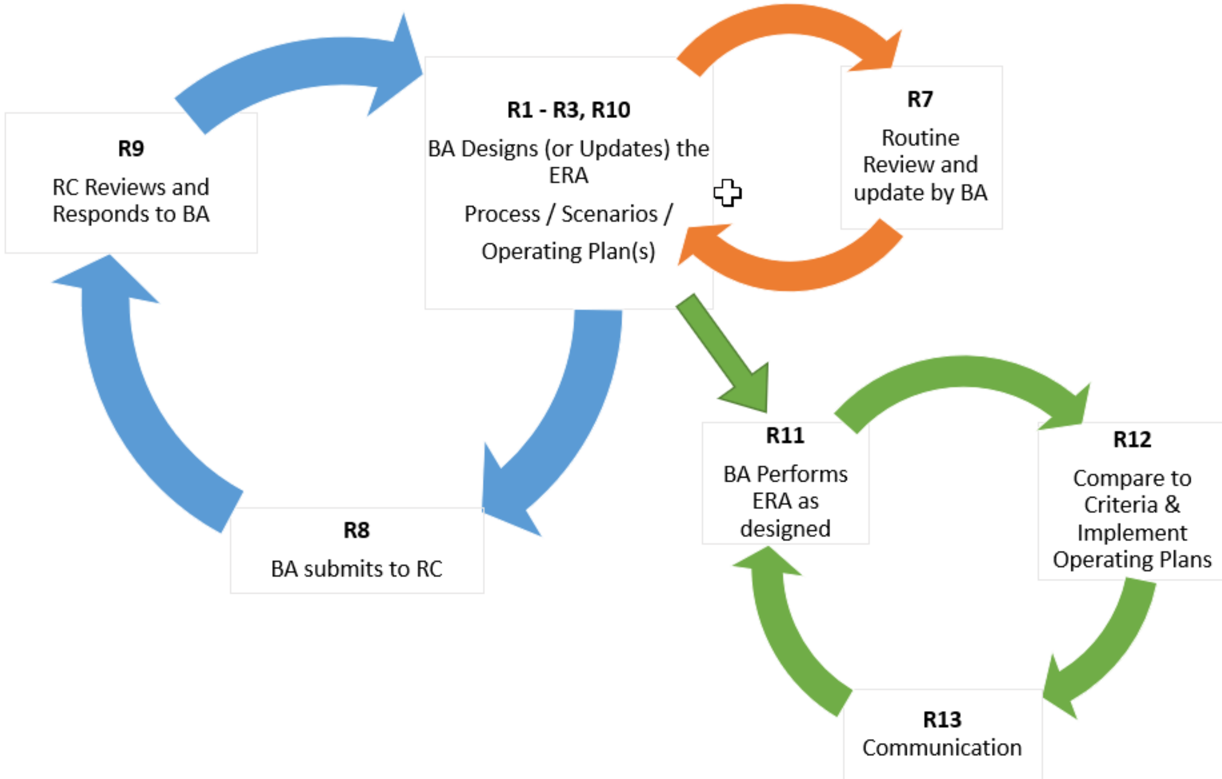

Figure 1. Process Diagram of ERA Requirements

Relationship to Other Standards

While the proposed standard has similarities to other standards, especially BAL-007, TOP-001, TOP-002, and EOP-011 standards, the proposed standard addresses reliability risks due to gaps in the existing reliability standards by focusing on a different time horizon than current standards and energy risks which are not clearly addressed. In many cases, the language is intentionally similar to language in those requirements but applicable to different time horizons. The BAL-007-1 standard looks at a near-term and the BAL-008-1 looks at the seasonal time horizon which is longer than other operations planning assessment requirements. In terms of addressing energy risks, both BAL-007-1 and BAL-008-1 more clearly outline the assessment requirements to look at energy over an assessment period rather than capacity assessments, generally used to comply with current standards.

TOP-001, TOP-002, and BAL-007 provide requirements for assessments and Operating Plans in real-time and operations planning time horizons, but their requirements are limited to up to six weeks ahead which may limit the options that Balancing Authorities may take to respond. BAL-008-1's proposed language extends this outlook to greater than five days and out to a season ahead, so BAs have the time to implement mitigation actions with longer lead times (e.g., reschedule outages, conserve consumable fuel, source additional fuel) and have better situational awareness of potential reliability risks.

TOP-002, EOP-011, BAL-007-1, and BAL-008-1 all require Operating Plans to minimize or mitigate reliability risks, but they would likely differ in what actions that a BA would deem appropriate to be included in each. Since BAL-008-1 is assessing a longer time horizon, the projected conditions are more uncertain, and the Operating Plans developed under BAL-008-1 should reflect that. Instead of specifying specific steps that must be taken, the Operating Plan can have more general processes and incorporate longer lead time activities than Operating Plans in BAL-007-1. BAL-008-1 Operating Plans are not intended to replace TOP-002, EOP-011, and BAL-007-1 developed Operating Plans but to implement actions that can only be implemented when potential risks are identified with a longer lead time. The goal of these longer-term Operating Plans is to reduce the likelihood of an actual Energy Emergency occurring which would require an EOP-011 Operating Plan or at least, reduce the severity of the Energy Emergency. Actions that are taken as outlined in the BAL-008-1 Operating Plans would then lead into the near-term Operating Plans (BAL-007-1) through the establishment of more favorable initial conditions, rather than overlapping them. This standard is similar to the near-term ERAs; the seasonal assessments give situational awareness about a longer time horizon and allow for longer lead time activities which should reduce the risk of identifying risks in the near-term ERA and eventually real time. Ideally, the longer-term Operating Plan(s), both seasonal and near-term, would result in the EOP-011 Operating Plan not being needed but if an Energy Emergency still occurs, the Operating Plans should have reduced the severity of the Energy Emergency.

Additionally, the BAL-008-1 assessment requires considering energy risk which can only be performed by looking at an assessment over a period with multiple timesteps and considering the depletion of stored energy and the production from just-in-time, variable energy resources. BAL-008-1 explicitly requires including these elements in an assessment and set criteria regarding when risks need to be addressed through Operating Plans.

The Balancing Authority (BA) may require additional data from other entities and should consider this when documenting the process. While BAL-008-1 does not require other entities to provide necessary data, TOP-003 requires the BA to "maintain a documented specification for the data necessary for it to perform its analysis functions…" in Requirement R2 and requires the other entities to provide the data in Requirement R5. Since these TOP-003 Requirements broadly give the BA the ability to request data "to perform its analysis functions" and does not limit that to assessments to a specific time horizon, TOP-003 should provide a mechanism for BAs to request and receive the necessary data for ERAs.

Requirement R1

Requirement R1 identifies the basis for defining what a seasonal ERA is. Time horizons and basic input assumptions in the seasonal assessment are specifically designed by each BA according to their risks and their supply and demand profiles. Because of differences in risks and in supply and demand profiles between regions, rather than requiring a set of prescriptive elements to assess, each BA is provided with minimum assessment requirements which they will use to define the scope for performing their ERAs and document a rationale.

Balancing Authorities may perform the required ERAs for just their area or a group of BAs may jointly perform their ERAs. Should a deficiency be identified, the BAs, regardless of whether they performed their assessment jointly or individually, can utilize their energy reserve sharing group of available resources. The goal of the ERA is to determine if sufficient energy is available. A review of the energy reserve sharing group should be performed to verify that it is sufficient to meet the groups combined needs. Again, the goal of the ERAs is to improve reliability for the system and the load.

The ERA process will include definitions for a duration, frequency, how they account for the necessary parameters to determine what the energy needs are, what resources can be used, and when to meet them. The duration should be a specified representative range for each season as identified by the BA, again providing for regional flexibility. It is understood that specific regions will have a different set of concerns and risks. Some regions have a resource mix that may include a large percentage of variable energy resources. Others may have risks due to either a non-firm fuel supply issue (e.g. non-firm gas supply) or non-firm transmission service due to system congestion. For example, a region that is heavily dependent on resources requiring more maintenance may need to look further into the future to manage these outages to confirm that there will be sufficient energy available. An entity with more variable energy resources with possible congestion may need to look more closely at the weather forecast and review their energy supply mix more frequently.

The process is intended to ensure that as changes in the resource mix or demand profiles become reality, they are captured appropriately and intentionally. New resource types are being introduced into the power system more frequently compared to years past, a trend that is expected to continue. Each new resource type comes with subtleties of how they perform and operate that may require a change to the way resources are portrayed in an ERA. Forecasted weather events that occur within a BA’s footprint (e.g., droughts, storms, calm and cloudy stretches) will also change the expected resource availability when an ERA is performed. Seasonal ERAs are intended to be performed on a routine basis and assess the time period that covers a season, making sure to study periods of concern. The time horizon of a season assessment offers a different vantage point verses the near-term assessment. Seasonal ERAs will tend to be more of a risk assessment with an array of possible conditions which a BA can evaluate.

Demand profiles will be determined by the BA as well. Entities will have a number of items to consider prior to determining their demand profile. It is up to the BA to determine exactly how Demand will be modeled, including considerations of how the variety of types of demand response are treated. A BA may choose to include market based or dispatchable demand response but it is recommended that other forms of demand response should not be included, which would leave load reduction options as a last resort (e.g., voltage reduction, load cycling, etc.). Each BA will need to identify what their type of demand response is and when, if ever, to consider it. Load shed should only be identified as part of a plan if this is the last resort.

ERAs must ensure that all periods of time are assessed. For the seasonal ERA, entities may choose to study only a shorter duration, representative subset of a season which could occur at any point during the season being evaluated and represents periods that they have identified to be a higher risk. For example, while the entity is evaluating a five month summer season, they may only look specifically at a three week period that they have identified as posing a higher risk. All five months are considered to be assessed in this example. The determination of how long to study will be based on several factors such as a typical cold snap or heat wave duration, system or generation outage recall timing, accuracy of forecast information beyond the near-term, duration of periods with low variable energy resource production, or lead time for fuel procurement and replenishment.

The seasonal ERA should be designed to look at the upcoming seasons within the next 12 months. Only evaluating one season for the year is likely not sufficient for the seasonal ERAs. BAs in North America experience some level of differentiation between time periods (seasons) over the course of a year and those differences must be considered in seasonal ERAs. It is not required that a full 90-120 day season is included in an seasonal ERA, but does require that the BA performing the ERA documents the rationale for why the time horizon and duration were selected.

The minimum amount of information that must be included in every ERA is identified in the standard. Based on the region of the BA performing the ERA, more information might be needed than for others. The standard does not contain an all-inclusive list. If other parameters are necessary for a BA to fully model the energy landscape for the ERA, they should be included and documented with a rationale for inclusion and selection.

Requirement R2

Requirement R2 outlines a minimum set of scenarios to be included in an ERA. The intent is to provide a mechanism for each BA to gauge how close to an Energy Emergency they may be in certain situations. Credibility of the Scenarios is for the BA to define and document.

There are four types of scenarios, three for supply and one Demand, that can be studied independently or in combination with each other. At least one parameter should be varied enough to stress the system to determine if the available resources are robust enough to meet the Demand and Operating Reserves. A possible load Scenario could be raising Demand from a 50/50 profile to a higher profile, such as a 90/10 or maximum load Scenario, to measure the impact to the system and determine if shortfalls are detected. There are three supply side Scenarios to be studied. The first is a credible energy contingency that removes one of the largest energy resources from the base case and runs it again. Large energy resources may be the same as large capacity resources, but not necessarily in all ERA study cases. The second supply Scenario removes a credible set of resources that are supplied by the same fuel supply. This is traditionally thought of as natural gas supplying multiple generating stations and may be just that, but could also be a set of wind turbines that are closely situated where a storm could render them unavailable for a period of time or solar panels that are covered by snow or smoke from a fire. The final scenario is a generator outage for an unplanned outage. Regardless of the chosen energy and fuel Scenarios, it is up to the BA to determine which resource or set of resources are included in the ERA. The choices by the BA in Scenarios should be documented and identified in their rationale.

In addition to the above defined scenarios, Requirement R2 specifies the consideration of “Other Scenarios with a credible or historical risk of occurring based on the best information available at the time of Scenario creation." An example of these Scenarios in a seasonal ERA includes a Scenario that stressed the System such as the impacts of a winter storm from the previous five years in the ERA for the next winter.

Requirement R3

The seasonal time horizon specified in BAL-008-1 offers a different vantage point than the near-term ERA. The actions that a BA can take due to an identified risk of an energy shortfall are different when identified weeks to months earlier than if waiting for a near term assessment. An example of actions that could be taken based on the results of a seasonal assessment that may not be available for a near-term assessment could include forward procurement of fuel, prioritizing or advancing key storage projects that are potentially available by the start of the season, requesting energy resources to update maintenance or construction plans to incorporate more flexibility that would then be available for use in near-term assessment Operating Plans is risks persist, postponement of major planned generation outage(s), or to change the sequencing of a transmission outage. If an entity were to wait for the near-term assessment to identify a risk, fewer options for the BA to avoid an energy risk in real time would be available.

Requirement R3 requires BAs to develop Operating Plans prior to forecasting Energy Emergencies through ERAs to minimize their effects. These Operating Plans are developed so that in the event that an ERA shows that a BA may have insufficient energy, they will have an Operating Plan ready to implement, per Requirement R3, that has been reviewed and updated before system conditions are unfavorable and be ready for later implementation. Operating Plans are expected to include actions that can be performed by the BA within the seasonal time horizon for which the ERA is designed. The actions that BAs may include in Operating Plans will also provide information to the BA regarding how far in advance the ERA might need to be completed (Requirement R1) such that they can have time to accomplish the actions identified. For example, if actions that could minimize potential Energy Emergencies take two months to accomplish, the BA should consider completing the seasonal ERA at least two months ahead of the season so that those options would be available.

As discussed in the Relationship to other Standards section, the Operating Plans developed based on this requirement are not intended to supersede Operating Plans associated with TOP and EOP standards or BAL-007-1, but to complement them and include actions that will reduce the likelihood or severity of an energy deficiency occurring in real-time. To that end, the BA develops an appropriate Operating Plan for a forecasted Energy Emergency that is identified by an ERA. Depending if the ERA is completed weeks or months prior to the forecasted Energy Emergency, the BA decides on suitable plans to reduce the impact. Since the Operating Plans are being implemented based on assessments looking weeks to months ahead, considering the associated uncertainty of the results, BAs may decide to exclude actions in the BAL-008-1 Operating Plans which would only need to occur much closer to the projected event or only plan to implement those actions if the projected conditions of the ERA appear that they will still occur. For example, an Operating Plan for a seasonal ERA may include increasing the frequency and duration for the associated near-term ERAs in order to monitor whether the forecasted Energy Emergency is more or less likely as the uncertainty of input data to the assessment decreases and other actions in the Operating Plan have been implemented. Again, the goal of performing an ERA is to identify those times when a forecasted Energy

Emergency might occur. The developed Operating Plan should have steps that can be taken to minimize, or mitigate, the forecasted Energy Emergency.

The ERA Operating Plans should be designed to be adaptable to unfolding conditions and proactive enough to possibly avoid an energy shortage through advanced actions. As an example, to illustrate the Operating Plan uses, when an ERA is completed 31 days ahead of a calculated shortfall then potential actions have a four-week timeline to perform the appropriate action plans as well as monitor if the identified risk conditions have changed. For instance, if the results of a three week-duration ERA that focuses on an extremely cold period determines an energy emergency may occur, the BA's Operating Plan could include the following actions:

- Facilitate the forward purchase of additional fuel to be available when a near-term ERA identifies the same shortfall using more accurate input data.
- Survey scheduled outage system to determine if any generation currently out for maintenance can return earlier than planned.
- Survey if any transmission outages affect either generation deliverability or import capability. If yes, can they be returned to service prior to the Energy Emergency.
- Survey if generation and transmission scheduled to go out can execute their outage plans in a manner that would minimize recall times.
- Notify RC and relevant entities of the projected risk (e.g., Generator Operations, relevant government authorities for assessing the need and strategy for public appeals or other BAs to account for expected imports or exports).
- Make sure all energy storage units can be fully available to help mitigate energy shortfalls.
- Increase frequency of performance of near-term ERAs, assess energy availability and have Operating Plan actions conditional on the level of risk.

Ideally, these actions will minimize or prevent an Energy Emergency that might occur in real-time. However, if the Energy Emergency still occurs, these actions should reduce the energy shortfall and better prepare the BAs to implement an emergency Operating Plan. This scenario is intended only to be one simple illustrative example that does not reflect all potential Operating Plan actions or actions that BAs in all regions can do.

While scheduling increased imports can be a part of the Operating Plan, it is imperative that the BA verify that the resources they have scheduled will continue to be there to solve their Energy Emergency. It should not be assumed that once imports are scheduled, this energy is a firm supply. Both BAs may be impacted by the event causing an Energy Emergency for both. The supplying entity may not be able to honor their agreement to provide this energy.

Requirement R4

The drafting team identified that BAs may need to request data necessary for them to complete their analysis functions, including the completion of an ERA, from the entities identified in TOP-003. However, as some BAs may also need information from the Resource Planner (RP) for the work associated with BAL-008-1, three requirements have been included in BAL-008-1. Requirement R4 identifies that the BA shall develop a data specification for the Resource Planner should they determine they need information for the completion of the seasonal ERA. Requirement R4 identifies three parts to the data specification: the data needed by the BA from the RP to support its seasonal ERA, how frequently the data should be provided, and the deadline for providing the information.

Requirement R5

Requirement R5 identifies that the BA shall distribute its data specification to all of the Resource Planners that they determine they need information from for the completion of their seasonal ERA in accordance with Requirement R4.

Requirement R6

Requirement R6 requires the Resource Planner to work with any BAs that provide a data specification for their seasonal ERA. The RP and the BA are to identify a mutually agreeable format, process for resolving data conflicts, and data security protocol for the Resource Planner, for the work associated with BAL-008-1.

Requirement R7

Requirement R7 requires that the BA review their process, Scenarios or method for creating, and Operating Plans, in Requirements R1 through R3, to determine if any changes are needed. The BA shall review this documentation no less than once every 24 months. Due diligence during the design and review phases is very important, as the BA is required to identify potential risks and possible actions that could minimize those risks that would lead to an energy shortfall in the seasonal timeframe.

Requirement R8

Requirement R8 provides a channel of communication between a BA and their associated RC. Requirement R8 is simply a BA providing their ERA process documentation, as defined by R1, R2, and R3, to the RC. The BA and the RC shall develop a mutually agreed-upon schedule, no greater than every 24 months. Depending on the RC, this may be requested more frequently. The designed process, along with the base condition, Scenarios or method for their creation, and Operating Plan(s) are all part of the package that needs to be reviewed.

Requirement R9

Providing ERA information to the RC under Requirement R8 is paired with this Requirement for the RC to review each package within 60 days of receipt. The RC review is intended to identify risks that may not have been considered for Wide Area reliability and ensure all identified risks are communicated to the BA. Coordination is required to ensure that there are no conflicting assumptions between BAs. Once a review is complete, the RC notifies the BA, and any necessary changes that occur within Requirement R9. For example, an assumption by two BAs, sharing a common transmission interface, each identifying an import condition during the same time period would result in an infeasible allocation of energy resources and would trigger an RC notification. The RC review provides additional reliability benefits, by comparing the BA's ERA information to that of other BAs, allowing for identification and clarification of discrepancies and/or opportunities for enhancements to strengthen the contents of a BA's ERA package.

It is the intention for implementing BAL-008-1 that the routine review of each ERA package by the RC can be accomplished within the required timeframe. However, it is understood that when ERAs are newly designed, along with Scenarios and Operating Plans, that more time will be needed by the RC to perform a thorough review. For this reason, implementation of Requirements 7 through 13 have an additional six months.

Requirement R10

Requirement R10 is the third part of the communication between the RC and BA where the BA is required to address any issues identified by the RC and resubmit their ERA process, ERA Scenarios or the method for creation, and Operating Plan(s). This requirement ensures the closing of the communication loop and documentation that the RC's review comments generated in Requirement R9 are addressed. Requiring the BA to address and document responses to feedback generated by the RC review ensures that the reliability benefits described in Requirement 9 of an RC's cross-comparison of packages from multiple BAs are enshrined and potential wide area reliability risks minimized or avoided.

Requirement R11

Requirement R11 specifies that the seasonal ERAs be performed as designed, reviewed, and approved.

Requirement R12

Requirement R12 specifies what constitutes three different circumstances that identify a forecasted Energy Emergency. The forecasted Energy Emergency conditions are intended to be a clear threshold where the ERA results identify levels of impending risk and require actions be performed to minimize the potential they will occur. The definitions of what constitutes a forecasted Energy Emergency are in alignment with the Energy Emergency Alert (EEA) definitions in EOP-011. The difference for BAL-008-1 is that instead of being a real time Energy Emergency, these would be forecasted events. The goal here is that if an Energy Emergency is forecasted in an ERA, the associated Operating Plan will have targeted steps to help minimize the Energy Emergency before it gets to next day and real time.

There are three EEA levels and three levels of forecasted Energy Emergencies. The criteria for a forecasted Energy Emergency apply also to Scenarios identified in Requirement R2 and studied in Requirement R11. This level of granularity allows for the BA to design an Operating Plan that fits the specific situation. Given Scenarios may be expected to enter the lower levels of an Energy Emergency, and the actions in an Operating Plan should be appropriate for that combination.

Finally, by leveraging the existing terms used in EOP-011 for EEA, clear and well-understood definitions are already in place which require little to no training, beyond the advanced timing associated with BAL-008-1. BAs have existing interpretations of how they respond when nearing or entering an EEA and the existing interpretations are expected to be used, including those that involve interaction with Reserve Sharing Groups.

Requirement R13

After receipt of notification from the BA that an Operating Plan is being implemented, Requirement R13 requires communication between the RC and Transmission Operators, other BAs within their footprint, and neighboring RCs. The time requirements for the notifications for the seasonal ERAs is seven calendar days. This action should require no more than an hour but may require some additional internal discussion or communication between the BA and RC, thus the additional time. The purpose of these communication requirements is to provide situational awareness from the RC to other entities that may be impacted by a forecasted Energy Emergency in a BA. With this information, other BAs and Transmission Operators can better plan for their own reliability risk, especially if they expected to rely on neighboring BAs for imports. Additionally, the RC receiving this information from multiple BAs allows the RC to have a wide area view of the energy risk and provide any insight they may have to minimize it. This communication is required only after the RC receives notification, which is one of the provisions required in the development of Operating Plans in Requirement R3.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2022-03 Energy Assurance with Energy-Constrained Resources

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2022-03 Energy Assurance with Energy-Constrained Resources. 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 DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

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

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

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard

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

Guideline (3) – Consistency among Reliability Standards

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

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

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

VRF Justifications for BAL-007-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the process for conducting Energy Reliability Assessments for the near-term time horizon which are required in defining the minimum standards by which Energy Reliability Assessments will be performed 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 BAL-007-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority documented an Energy Reliability Assessment process for the near-term time horizon but did not account for one of the elements in Requirement R1 Part 1.1 through Part 1.3. OR The Balancing Authority documented a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon accounting for each of the elements in Requirement R1 Parts 1.1 through 1.3 but failed to maintain it.	The Balancing Authority documented an Energy Reliability Assessment process for the near-term time horizon but did not account for two or more of the elements in Requirement R1 Part 1.1 through Part 1.3. OR The Balancing Authority documented an Energy Reliability Assessment process for the near-term time horizon but did not provide a rationale in accordance with Requirement R1 Part 1.4.	The Balancing Authority failed to document an Energy Reliability Assessment process for the near-term time horizon.

VSL Justifications for BAL-007-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for BAL-007-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining a set of scenarios or a method of Scenario creation which are required in defining the minimum standards by which near-term Energy Reliability Assessments will be performed 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 BAL-007-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not maintain it. OR The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include a rationale for the Scenarios or method identified.	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not vary conditions by a sufficient amount to stress the system or include all of the conditions listed in Requirement R2 Parts 2.1 through 2.3.	The Balancing Authority failed to document a set of Scenarios or a method of Scenario creation for use in performing near-term ERAs.

VSL Justifications for BAL-007-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not 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 BAL-007-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term Energy Reliability Assessment, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s) 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 BAL-007-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority documented and maintained an Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term ERA but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term ERA.

VSL Justifications for BAL-007-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R4	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that reviewing and updating, if necessary, the near-term Energy Reliability Assessment process, near-term Energy Reliability Assessment scenarios or methods, and Operating Plan(s) developed under Requirements R1 through R3, at least every 24 calendar months, is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restoration 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 Low 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 Low 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 low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-007-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority reviewed information that contained the near-term ERA process, the ERA scenarios or methods, and Operating Plan(s) but failed to update within 24 months.	The Balancing Authority failed to review and update, if necessary, information that contained the near-term ERA process, the ERA scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.

VSL Justifications for BAL-007-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment 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 BAL-007-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not providing the near-term Energy Reliability Assessment process, near-term Energy Reliability Assessment scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule 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 BAL-007-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority submitted information that contained the near-term ERA process, the ERA scenarios, and Operating Plan(s) but failed to submit to the Reliability Coordinator within 24 months, on a mutually agreed-upon schedule.	The Balancing Authority failed to submit information that contained the near-term ERA process, the ERA scenarios, and Operating Plan(s) to the Reliability Coordinator.

VSL Justifications for BAL-007-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 BAL-007-1, Requirement R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that the Reliability Coordinator did not complete the steps in Requirements R9.1 and R9.2 within 60 calendar days to ensure the most accurate information is used, 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 BAL-007-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but notified one or more Balancing Authority of the results of its review in a time period that was longer than 60 calendar days but less than 90 calendar days.	The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but notified one or more Balancing Authorities of the results of its review in a time period that was longer than 90 calendar days but less than 120 calendar days.	The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but failed to notify each Balancing Authority of the results of its review within 120 calendar days.

VSL Justifications for BAL-007-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <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 BAL-007-1, Requirement R7	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that if each Balancing Authority did not address any reliability risks identified by its Reliability Coordinator and resubmit the updated information required in Requirement R4 to its Reliability Coordinator within 60 calendar days of receipt 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 BAL-007-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority addressed any reliability risks identified by its Reliability Coordinator but failed to resubmit the updated information within 60 calendar days following receipt.	The Balancing Authority failed to address any reliability risks identified by its Reliability Coordinator. OR The Balancing Authority failed to resubmit the updated information required in Requirement R4 to its Reliability Coordinator.

VSL Justifications for BAL-007-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R8	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that near-term Energy Reliability Assessments were not performed according to the process documented in Requirement R1 using the scenarios or methods documented in Requirement R2 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 BAL-007-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to perform a near-term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.

VSL Justifications for BAL-007-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R9	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that if an Operating Plan(s) was not implemented once a near-term Energy Reliability Assessment identified one or more forecasted Energy Emergencies it 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 BAL-007-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a near-term ERA identified any of the forecasted conditions in Requirement R8.

VSL Justifications for BAL-007-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R10	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that each if a Reliability Coordinator did not notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of the forecasted condition(s) and the Balancing Authority's Operating Plan(s) 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 BAL-007-1, Requirement R10			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R9 but notified one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 24-25 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R9 but notified one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 25-26 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R9 but notified one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 26-27 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R8 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators within 27 hours or more of receiving notification.

VSL Justifications for BAL-007-1, Requirement R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL uses the same terminology as used in the associated requirement and is, 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.

Violation Risk Factor and Violation Severity Level Justifications

Project 2022-03 Energy Assurance with Energy-Constrained Resources

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2022-03 Energy Assurance with Energy-Constrained Resources. 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 DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

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

Lower Risk Requirement

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

FERC Guidelines for Violation Risk Factors

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

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

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

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

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

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

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

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

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

VRF Justifications for BAL-008-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the process for the seasonal Energy Reliability Assessments which are required in defining the minimum standards by which seasonal Energy Reliability Assessments will be performed 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 BAL-008-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority documented an ERA process document for the seasonal time horizon accounting for each of the elements in Requirement R1 Parts 1.1 through 1.4 but failed to maintain it at least annually.	The Balancing Authority documented and maintained an ERA process document for the seasonal time horizon but did not account for one or more of the elements under Requirement R1 Part 1.4. OR The Balancing Authority documented a seasonal ERA process but did not provide a supporting rationale(s) under Requirement R1 Part 1.1 and Part 1.4 for the seasonal time horizon.	The Balancing Authority documented and maintained an ERA process document for the seasonal time horizon but failed to include two or more of the required elements under Requirement R1 Part 1.4 or supporting rationale(s) under Requirement R1 Part 1.1 and Part 1.4 for the seasonal time horizon. OR The Balancing Authority failed to document a Reliability Coordinator-reviewed Energy Reliability Assessment process for the seasonal time horizon.

VSL Justifications for BAL-008-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 BAL-008-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining a set of scenarios or method of scenario creation for use in performing the seasonal Energy Reliability Assessments which are required in defining the minimum standards by which Energy Reliability Assessments will be performed 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 BAL-008-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority documented the seasonal ERA set of Scenarios or method of Scenario creation but failed to maintain them. OR The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include a rationale for the Scenarios or method identified.	The Balancing Authority documented and maintained the seasonal ERA set of Scenarios or a method of Scenario creation but failed to include one of the Scenarios or method of Scenario creation in Requirement R2 Part 2.1, Part 2.2 and Part 2.3 or supporting rationales under Requirement R2.	The Balancing Authority documented and maintained the seasonal ERA set of Scenarios or a method of Scenario creation but failed to include two or more of the Scenarios in Requirement R2 Part 2.1, Part 2.2, and Part 2.3 or supporting rationales under Requirement R2. OR The Balancing Authority failed to document the seasonal ERA set of Scenarios or a method of Scenario creation.

VSL Justifications for BAL-008-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 BAL-008-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the Operating Plan(s) to minimize forecasted Energy Emergencies, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s) 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 BAL-008-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority documented and maintained Operating Plan(s) but failed to include a provision for notification for its Reliability Coordinator.	The Balancing Authority failed to develop Operating Plan(s) to minimize forecasted Energy Emergencies identified in the seasonal ERAs.

VSL Justifications for BAL-008-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL uses the same terminology as used in the associated requirement and is, 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 BAL-008-1, Requirement R4	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that by not maintaining a documented specification for the data necessary from its Resource Planner(s) to perform seasonal Energy Reliability Assessments is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restoration 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 Low 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 Low 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 low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-008-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority maintained a documented data specification for the seasonal ERA but failed to include one of the elements in Requirement R4 Part 4.1, Part 4.2, and Part 4.3.	The Balancing Authority maintained a documented data specification for the seasonal ERA but failed to include two or more of the elements in Requirement R4 Part 4.1, Part 4.2, and Part 4.3. OR The Balancing Authority failed to document a data specification for the seasonal ERA.

VSL Justifications for BAL-008-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 BAL-008-1, Requirement R5	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that by distributing the data specification to its Resource Planner that have data required by the Balancing Authority to perform seasonal Energy Reliability Assessments is administrative in nature and a requirement in an operations planning time frame that, if violated, would not, under the emergency, abnormal, or restoration 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 Low 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 Low 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 low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-008-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to distribute its data specification to its Resource Planner(s) that have data required by its Balancing Authority for its seasonal ERA.

VSL Justifications for BAL-008-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does 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 BAL-008-1, Requirement R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not satisfying the obligations of the documented specifications using criteria in Requirements R6.1 through R6.3 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 BAL-008-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Resource Planner failed to satisfy the obligations of the documented data specification.

VSL Justifications for BAL-008-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does 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 BAL-008-1, Requirement R7	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that by reviewing and updating, if necessary, the seasonal Energy Reliability Assessment process, seasonal Energy Reliability Assessment scenarios or methods, and Operating Plan(s) developed under Requirements R1 through R3, at least every 24 calendar months, is administrative in nature and a requirement in an operations planning time frame that, if violated, would not, under the emergency, abnormal, or restoration 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 Low 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 Low 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 low VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-008-1, Requirement R7			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority reviewed the seasonal ERA process, the seasonal ERA Scenarios or methods of Scenario creation, and Operating Plan(s) but failed to update its Reliability Coordinator within the mutually agreed-upon schedule.	The Balancing Authority failed to review or update information that contained the seasonal ERA process, the seasonal ERA scenarios or methods of Scenario creation, and Operating Plan(s) to its Reliability Coordinator.

VSL Justifications for BAL-008-1, Requirement R7	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL uses the same terminology as used in the associated requirement and is, 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 BAL-008-1, Requirement R8	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of Low is appropriate due to the fact that by providing the seasonal Energy Reliability Assessment process, seasonal Energy Reliability Assessment scenarios or methods, and Operating Plan(s) developed under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule is administrative in nature and a requirement in an operations planning time frame that, if violated, would not, under the emergency, abnormal, or restoration 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 Low 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 Low 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 low VRF requirement per the criteria filed with FERC as part of the ERO’s Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-008-1, Requirement R8			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority submitted information that contained the seasonal ERA process, the ERA Scenarios, and Operating Plan(s) but failed to submit to the Reliability Coordinator within 24 months, on a mutually agreed-upon schedule.	The Balancing Authority failed to submit information that contained the seasonal ERA process, the ERA Scenarios, and Operating Plan(s) to the Reliability Coordinator.

VSL Justifications for BAL-008-1, Requirement R8	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL uses the same terminology as used in the associated requirement and is, 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 BAL-008-1, Requirement R9	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that the Reliability Coordinator did not complete the steps in Requirements R9.1 and R9.2 within 60 calendar days to ensure the most accurate information is used 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 BAL-008-1, Requirement R9			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' seasonal ERA information to avoid risks to Wide Area reliability but failed to notify each Balancing Authority of results of its review within 60 calendar days.	The Reliability Coordinator failed to review the information in Requirement R8 for coordination with other Balancing Authorities' seasonal ERA information to avoid risks to Wide Area reliability.

VSL Justifications for BAL-008-1, Requirement R9	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL uses the same terminology as used in the associated requirement and is, 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 BAL-008-1, Requirement R10	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that if each Balancing Authority did not address any reliability risks identified by its Reliability Coordinator and resubmit the updated information required in Requirement R8 to its Reliability Coordinator within 60 calendar days of receipt 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 BAL-008-1, Requirement R10			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority addressed any reliability risks identified by its Reliability Coordinator and resubmitted the updated information required in Requirement R7 to its Reliability Coordinator but resubmitted the updated information more than 60 calendar days following receipt.	The Balancing Authority failed to address any reliability risks identified by its Reliability Coordinator. OR The Balancing Authority failed to resubmit the updated information required in Requirement R7 to its Reliability Coordinator.

VSL Justifications for BAL-008-1, Requirement R10	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 BAL-008-1, Requirement R11	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that if the seasonal Energy Reliability Assessments was not performed according to the process documented in Requirement R1 using the scenarios or methods documented in Requirement R2 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 BAL-008-1, Requirement R11			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to perform seasonal ERAs in accordance with its process documented in Requirement R1 using the Scenarios or methods of Scenario creation documented in Requirement R2.

VSL Justifications for BAL-008-1, Requirement R11	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does 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 BAL-008-1, Requirement R12	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that if an Operating Plan(s) was not implemented once a seasonal Energy Reliability Assessment identified one or more forecasted Energy Emergencies it 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 BAL-008-1, Requirement R12			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a seasonal ERA identified any of the forecasted conditions in Requirement R12.

VSL Justifications for BAL-008-1, Requirement R12	
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 is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does 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 BAL-008-1, Requirement R13	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that if a Reliability Coordinator did not notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of the forecasted condition(s) and the Balancing Authority's Operating Plan(s) 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 BAL-008-1, Requirement R13			
Lower	**Moderate**	**High**	**Severe**
The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R13 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 24-48 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R13 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 48-72 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R13 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinator Area between 72-96 hours of receiving notification.	The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R13 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordaintors of the forecasted condition(s) and the Balancing Authority's Operating Plan(s) after 96 hours.

VSL Justifications for BAL-008-1, Requirement R13	
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.

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UPDATED
Standards Announcement
Project 2022-03 Energy Assurance with Energy-Constrained Resources

Formal Comment Period Extended, Now Open through June 24, 2024

Now Available

The formal comment period for **BAL-007-1 - Near-term Energy Reliability Assessments** and **BAL-008-1 - Seasonal Energy Reliability Assessments** has been extended and is now open through **8 p.m. Eastern, Monday, June 24, 2024**.

Regarding BAL-007-1, 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.

Next Steps
Additional ballots for BAL-007-1 and initial ballots for BAL-008-1 and their implementation plans, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels have been extended and will now be conducted **June 11 – 24, 2024**.

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

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2022-03 Energy Assurance with Energy-Constrained Resources 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

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Formal Comment Period Open through June 20, 2024
Ballot Pools for BAL-008-1 Open through June 5, 2024

Now Available

A 45-day formal comment period for draft two of **BAL-007-1 - Near-term Energy Reliability Assessments** and draft one of **BAL-008-1 - Seasonal Energy Reliability Assessments**, is open through **8 p.m. Eastern, Thursday, June 20, 2024**.

Regarding BAL-007-1, the standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Ballot Pools

The existing BAL-007-1 ballot pools were used for all the BAL-008-1 ballots. The BAL-008-1 ballot pools have been re-opened to allow stakeholders to join if they are not existing members. Registered Ballot Body voters can join the ballot pools here by **8 p.m. Eastern, Wednesday, June 5, 2024.**

- *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.*

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.

Next Steps

Additional ballots for BAL-007-1 and initial ballots for BAL-008-1 and their implementation plans, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 11 – 20, 2024**.

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

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources 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:	2022-03 Energy Assurance with Energy-Constrained Resources
Comment Period Start Date:	5/7/2024
Comment Period End Date:	6/24/2024
Associated Ballots:	

There were 64 sets of responses, including comments from approximately 161 different people from approximately 99 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. BAL-007-1 Near-term ERAs: The standards drafting team (SDT) modified the Energy Reliability Assessment (ERA) definition based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification.

2. BAL-007-1 Near-term ERAs: Based on industry feedback, the SDT updated Requirement R1 to clarify what near-term ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

3. BAL-007-1 Near-term ERAs: The SDT updated Requirements R2 through Requirement R8 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

4. BAL-007-1 Near-term ERAs: The SDT proposes entities use forecasted Demand profiles for the time interval under study for the BAL-007 assessment. The SDT's goal is to align measures for ERAs with those used for EOP-011. Actions taken as part of a BAL-007 Operating Plan should be targeted to minimize any Energy Emergency events. Do you agree with the updated proposed language in Requirement R8? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

5. BAL-007-1 Near-term ERAs: The SDT updated Requirement R9 based on industry feedback. Do you agree with the updated proposed language in Requirement R9? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

6. BAL-007-1 Near-term ERAs: The SDT updated the implementation plan to allow for 18 months for Requirements R1 through R3 and 24 months for Requirements R4 through Requirement R10 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

7. BAL-007-1 Near-term ERAs: The SDT believes that fuel data information needed to address BAL-007-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

8. BAL-007-1 Near-term ERAs: The SDT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

9. BAL-007-1 Near-term ERAs: Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

10. BAL-008-1 Seasonal ERAs: The SDT drafted BA-008-1 Requirement R1 to clarify what seasonal ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

11. BAL-008-1 Seasonal ERAs: The SDT drafted BAL-008-1 Requirements R2 through R13 based on industry feedback regarding seasonal ERAs. Do you agree with the proposed requirements? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

12. BAL-008-1 Seasonal ERAs: The SDT drafted the BAL-008-1 implementation plan to allow for 18 months for Requirements R1 through R6 and 24 months for Requirements R7- R13 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

13. BAL-008-1 Seasonal ERAs: The SDT believes that fuel data information needed to address BAL-008-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

14. BAL-008-1 Seasonal ERAs: The SDT proposes that the newly proposed BAL-008-1 meets the Standards Authorization Request 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.

15. BAL-008-1 Seasonal ERAs: Provide any BAL-008-1 additional comments for the SDT 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
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO

					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
Public Utility District No. 1 of Chelan County	Anne Kronshage	1,3,5,6		Public Utility District No. 1 of Chelan County - Voting Group	Anne Kronshage	Public Utility District No. 1 of Chelan County	6	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	MRO,SPP RE,WECC	SRC Energy Assurance	Charles Yeung	SPP	2	MRO
					Elizabeth Davis	PJM	2	RF
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Greg Campoli	NYISO	2	NPCC
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
WEC Energy Group, Inc.	Christine Kane	3,4,5,6		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
NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk	3,5,6		NIPSCO	Dmitriy Bazylyuk	NiSource - Northern Indiana Public Service Co.	6	RF
					Kathryn Tackett	NiSource - Northern	5	RF

						Indiana Public Service Co.		
					Steven Taddeucci	NiSource - Northern Indiana Public Service Co.	3	RF
					Alison Nickells	NiSource - Northern Indiana Public Service Co.	1	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
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
Eversource Energy	Joshua London	1,3		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
Florida Municipal Power Agency	LaKenya Vannorman	3,5,6	SERC	Florida Municipal Power Agency (FMPA)	Chris Gowder	Florida Municipal Power Agency	5	SERC
					Navid Nowakhtar	Florida Municipal Power Agency	3	SERC
					Jade Bulitta	Florida Municipal Power Agency	6	SERC
DTE Energy - Detroit Edison Company	Mohamad Elhusseini	3,5		DTE Energy	Mohamad Elhusseini	DTE Energy	5	RF
					Patricia Ireland	DTE Energy	4	RF

					Marvin Johnson	DTE Energy - Detroit Edison Company	3	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC

					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC

					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	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
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Heather Harris	Southwest Power Pool Inc.	2	MRO
					Ashley Stringer	Southwest Power Pool Inc.	2	MRO
					Jim Williams	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Mason Favazza	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO

					Margaret Quispe	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Sacramento Municipal Utility District	Tim Kelley	1,3,4,5,6	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
Santee Cooper	Vicky Budreau	1,3,5,6		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Christie Pope	Santee Cooper	1,3,5,6	SERC

1. BAL-007-1 Near-term ERAs: The standards drafting team (SDT) modified the Energy Reliability Assessment (ERA) definition based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification.

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

Idaho Power agrees with WPP's response to this question, shown below.

Though the current definition is better than the previous versions, the phrase "...a process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon." is passive and may be better stated as "...a process for conducting near-term Energy Reliability Assessments (ERA)". The addition of using "...near-term time horizon" confuses this term with "Near-Term Planning Horizon" and "Near-Term Transmission Planning Horizon" that many entities are familiar with and are used in other NERC Standards.

It is still unclear why the ERA is elevated to two new standards and why it is not incorporated into TOP-002 Operating Plans. Adding an Energy Reliability criteria in TOP-002-4 R4 would be sufficient and would reduce the need for separate assessments, compliance documentation and corrective action plans. During enforcement, due to the ERA terminology, auditors will be focused on finding ERA specific documentation, rather than daily and near-term operating plans that some BAs typically use to show compliance . This exposes organizations to administrative compliance risk if they combine their ERA process into their TOP-002 Operating Plans.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

Seattle City Light agrees with WPP Submitted Comment.

Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 1,3,4,5,6	
Answer	No

Document Name	
Comment	

I agree with the comments provided by Western Power Pool.

Likes 0	
Dislikes 0	
Response	

Michael Jang - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	
Comment	

SCL is in support and alignmnet with WPP's & Idaho's submitted comments.

Likes 0	
Dislikes 0	
Response	

Reed Adam - Seattle City Light - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

Though the current definition is better than the previous versions, the phrase "…a process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon." is passive and may be better stated as "…a process for conducting near-term Energy Reliability Assessments (ERA)". The addition of using "…near-term time horizon" confuses this term with "Near-Term Planning Horizon" and "Near-Term Transmission Planning Horizon" that many entities are familiar with and are used in other NERC Standards.
It is still unclear why the ERA is elevated to two new standards and why it is not incorporated into TOP-002 Operating Plans. Adding an Energy Reliability criteria in TOP-002-4 R4 would be sufficient and would reduce the need for separate assessments, compliance documentation and corrective action plans. During enforcement, due to the ERA terminology, auditors will be focused on finding ERA specific documentation, rather than daily and near-term operating plans that some BAs typically use to show compliance . This exposes organizations to administrative

Likes 0	
Dislikes 0	
Response	

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	
Peter Yost - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Supporting EEI comments on BAL-007 and BAL-008.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments and also is concerned that the definition does not have an energy componenet and energy is not clearly defined.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	
Please see BPA's full response in question 9.	
Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
CHPD supports WPP's response.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Though the current definition is better than the previous versions, the phrase "…a process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon." is passive and may be better stated as "…a process for conducting near-term Energy Reliability Assessments (ERA)". The addition of using "…near-term time horizon" confuses this term with "Near-Term Planning Horizon" and "Near-Term Transmission Planning Horizon" that many entities are familiar with and are used in other NERC Standards. It is still unclear why the ERA is elevated to two new standards and why it is not incorporated into TOP-002 Operating Plans. Adding an Energy Reliability criteria in TOP-002-4 R4 would be sufficient and would reduce the need for separate assessments, compliance documentation and corrective action plans. During enforcement, due to the ERA terminology, auditors will be focused on finding ERA specific documentation, rather than daily and near-term operating plans that some BAs typically use to show compliance. This exposes organizations to administrative compliance risk if they combine their ERA process into their TOP-002 Operating Plans.	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power supports the Western Power Pool comments.	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Still confusion around near-term time horizon with NER-Term Planning Horizon. Recommend incorporating the new studies into the existing TOP-002 standard and not create two new standards, OR at least put BAL-007 and BAL-008 into a single standard. Registered Entities will likely combine the process into their processes for TOP-002 thus producing one large set of compliance evidence.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	No
Document Name	
Comment	
The reality for entities with large hydraulic reservoirs, as is the case for HQ, is completely different from “fuel” constraints. Near term assessments begin 24-48 hours from the current day.	
Likes 0	
Dislikes 0	
Response	

Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	

Puget Sound Energy agrees with WPP's response to this question, shown below.

Though the current definition is better than the previous versions, the phrase "...a process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon." is passive and may be better stated as "...a process for conducting near-term Energy Reliability Assessments (ERA)". The addition of using "...near-term time horizon" confuses this term with "Near-Term Planning Horizon" and "Near-Term Transmission Planning Horizon" that many entities are familiar with and are used in other NERC Standards.

Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	

Puget Sound Energy agrees with WPP's response to this question, shown below.

Though the current definition is better than the previous versions, the phrase "...a process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon." is passive and may be better stated as "...a process for conducting near-term Energy Reliability Assessments (ERA)". The addition of using "...near-term time horizon" confuses this term with "Near-Term Planning Horizon" and "Near-Term Transmission Planning Horizon" that many entities are familiar with and are used in other NERC Standards.

Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

Seminole agrees with FRCC's comments below

The FRCC believes the current definition is not a significant improvement from the previous version.
Specifically, the statement:
"A process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon." is not well stated and may be better stated as "...a process for conducting near-term Energy Reliability Assessments (ERA)".
Also, using "near-term time horizon" can lead to confusion with the terms "Near-Term Planning Horizon" and "Near-Term Transmission Planning Horizon". These terms are currently defined in other enforceable NERC standards.
The FRCC believes that there is no compelling reason as to why the ERA has been included in two new enforceable NERC standards. It would better serve the industry to be incorporated into the current TOP-002 Operating Plans requirements. Incorporation of the proposed ERA requirements into TOP-002-4 R4 would satisfy the identified need for the ERA. TOP-002-4 already addresses the Operations Planning Time Horizon which includes day-ahead, up to, and including seasonal. Although R4 only addresses a next-day Operating Plan, this requirement could easily be modified to include the extended time period, or an additional requirement could be added and clarified within TOP-002-4. There are already requirements for distributing the Operating Plans to TOPs and the RC. This would eliminate the need for separate assessments, the large increase in compliance documentation and corrective action plans.
The FRCC believes that there will be an increase in exposure risk on maintaining documentation of receipt, timing of receipt, and timing of review notification. The current proposed ERA terminology will place the audit focus on documentation that is only specific to the ERA requirements. The current operating process that produces the daily and near-term operating plans for BAs will be rendered to be ineffective in meeting this requirement.

Likes 0	
Dislikes 0	

Response

LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	

Comment

FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.

Likes 0	
Dislikes 0	

Response

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	No
Document Name	

Comment

The FRCC believes the current definition is not a significant improvement from the previous version.
Specifically, the statement:
“A process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon.” is not well stated and may be better stated as “...a process for conducting near-term Energy Reliability Assessments (ERA)”.
Also, using “near-term time horizon” can lead to confusion with the terms “Near-Term Planning Horizon” and “Near-Term Transmission Planning Horizon”. These terms are currently defined in other enforceable NERC standards.
The FRCC believes that there is no compelling reason as to why the ERA has been included in two new enforceable NERC standards. It would better serve the industry to be incorporated into the current TOP-002 Operating Plans requirements. Incorporation of the proposed ERA requirements into TOP-002-4 R4 would satisfy the identified need for the ERA. TOP-002-4 already addresses the Operations Planning Time Horizon which includes day-ahead, up to, and including seasonal. Although R4 only addresses a next-day Operating Plan, this requirement could easily be modified to include the extended time period, or an additional requirement could be added and clarified within TOP-002-4. There are already requirements for distributing the Operating Plans to TOPs and the RC. This would eliminate the need for separate assessments, the large increase in compliance documentation and corrective action plans.
The FRCC believes that there will be an increase in exposure risk on maintaining documentation of receipt, timing of receipt, and timing of review notification. The current proposed ERA terminology will place the audit focus on documentation that is only specific to the ERA requirements. The current operating process that produces the daily and near-term operating plans for BAs will be rendered to be ineffective in meeting this requirement.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

SMUD and BANC agree with the comments submitted by the Western Power Pool.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

The ERA evaluates the risk of resources being unable to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated evaluation period.

The purpose section in the introduction for BAL-007-1 is also missing a verb.

Likes 0	
Dislikes 0	

Response

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO

Answer	No
Document Name	

Comment

NIPSCO supports MISO's feedback.

Likes 0	
Dislikes 0	

Response

Chance Back - Muscatine Power and Water - 1,3,5,6

Answer	No
Document Name	

Comment

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Note: The same ERA definition applies under all the time horizons.	
Likes 1	Midcontinent ISO, Inc., 2, Welch Bobbi
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	EEI Near Final Draft Comments _ Project 2022-03 BAL-007 BAL-008 Rev 0g __6_11_2024.docx
Comment	
Supporting comments from EEI (attached)	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	Yes
Document Name	

Comment	
WEC Energy Group supports the comments submitted by EEI, and does not oppose the proposed definition.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation does not oppose the proposed definition for Energy Reliability Assessment (ERA).	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
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 oppose the proposed definition for Energy Reliability Assessment (ERA).	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren supports MISO's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	

Likes 0	
Dislikes 0	

Response

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting EEI comments.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

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 does not oppose the proposed definition for Energy Reliability Assessment (ERA).

Likes 0	
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
The same ERA definition applies under all the time horizons.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	Yes
Document Name	2022-03_Unofficial Comment Form_BAL-007 and BAL-008_SRC Comments-FINAL.docx
Comment	
Note: The same ERA definition applies under all the time horizons. The ERA definition appears to be missing a word; the ISO/RTO Council (IRC) Standards Review Committee (SRC) suggests that this be addressed by adding the word ‘necessary’ in the ERA definition:	

"Evaluation of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated evaluation period".	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	

Pattern Energy supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	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	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
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	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Greg Sorenson - ReliabilityFirst - 10 - RF

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

The ERA definition appears to be missing a word; MISO suggests that this be addressed by adding the word ‘necessary’ in the ERA definition:

“Evaluation of the resources ***necessary*** to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated evaluation period”.

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE asserts that an “Energy Assessment” means a systematic evaluation of the ability of the resources to reliably and adequately deliver energy to meet the system demand under a specific timeframe and set of system conditions associated with any perceived constraints (such as fuel constraints, cooling water availability or other environmental constraints). Therefore, the ERA should emphasize evaluation of the resource’s ability to reliably supply energy to the system. Texas RE recommends the following revision to the ERA definition (in bold):

Evaluation of the **ability** of resources to reliably **and adequately** supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated evaluation period.

Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	
Response	

2. BAL-007-1 Near-term ERAs: Based on industry feedback, the SDT updated Requirement R1 to clarify what near-term ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Alison MacKellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation has concerns on BAs developing their own process for lack of uniform requests to generator owners. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Michael Goggin - Grid Strategies LLC - 5	
Answer	No
Document Name	
Comment	
The drafting team should clarify how the requirement to account for "depletion of fuel" should be applied to interruptions to gas supply and transportation. This is important to clarify because correlated failures of gas generators, often due to fuel supply and transportation constraints and interruptions, have been the primary contributing factor in all recent cold snap events that have led to FERC-NERC reports. The drafting team should clarify that assessments should include the expected unavaiability of gas generators, informed by past experience during winter peak demand periods, when accounting for "resource capabilities and operations."	
Likes 0	
Dislikes 0	
Response	

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	

Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	

Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC agree with the comments submitted by the Western Power Pool.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	2022-03_Unofficial Comment Form_BAL-007 and BAL-008_MRO NSRF_06-11-24rev.docx
Comment	

The MRO NSRF supports and appreciates the direction taken by the Standard Drafting Team (SDT) to increase flexibility for BAs. While we agree Draft #2 is an improvement over Draft #1, we propose the following:

Modify Part 1.3.2. to align with Part 2.2

· Replace “depletion of fuel” with “fuel supply.” (Part 2.2.)

o “Depletion of fuel” is overly prescriptive and one-sided (fails to consider replenishment) whereas “fuel supply” allows for a broad consideration of all fuel supply factors without requiring the BA to maintain documentation specific to the depletion of fuel for each generating resource.

· Move “variable energy resources” and “electric storage” as examples to the Technical Rationale. It is misleading and incomplete for a standard to list a limited subset of resource technologies simply because they are “new.” There will be other technologies in the future. Examples are more appropriately located in the Technical Rationale.

· Add “unplanned generator outages” to Part 1.3.2 as this language will encompass all reasons leading to “unplanned generator outages/de-rates” and not limit it to fuel supply alone.

· Pursuant to the above comments, we suggest Part **1.3.2** be modified as shown below:

1.3.2. Known Resource capabilities and operations, including energy supply, fuel supply, unplanned generator outages and energy transfers between neighboring Balancing Authorities, and

§ Since Part 1.3.2 includes ‘resource capabilities,’ that should encompass transmission limitations. Therefore, the MRO NSRF requests Part 1.3.3 be stricken. If the SDT disagrees with removing Part 1.3.3. altogether, then MRO NSRF proposes the following modification:

1.3.3. Transmission outages that bottle generation and limit the generator’s output.

Likes 2	Midcontinent ISO, Inc., 2, Welch Bobbi; Muscatine Power and Water, 5, Back Chance
Dislikes 0	

Response

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	No
Document Name	

Comment

The FRCC believes that BAL-007 R1 does not appear to allow BAs to generate a region-wide ERA, based on the common practice of sharing of resources, coordinated generation resource dispatch, or Reserve Sharing Groups.
The FRCC believes there is no has been no allowance given to Resource Planners and/or BAs who may decide to complete these requirements through cooperative resource programs and that the proposed changes do not allow for BAs who have coordinated together on a region-wide Capacity and Energy Emergency Plan to use these plans for these requirements. These plans ensure that each BA throughout the region has taken all possible steps to avoid a declared Energy Emergency (EEA 2/3) or a capacity issue that could ultimately result in the shedding of Firm Native Customer Load. The requirement for each BA to create BA-specific ERAs could result in the lack of proper coordination between BAs and create a bigger risk to the interconnected Bulk Electric System.
The FRCC does not support the language in requirement 1.2.1 because it does not allow a BA the flexibility to determine the duration and frequency of performing an ERA and that performing studies to cover all time periods is extremely burdensome. It would be better for the BA to assess what time periods need to be covered based on their area and define that within their process.
and defined scenarios.
As proposed, this requirement would disproportionately increase the administrative burden

without increasing reliability.
The FRCC also proposes changing “depletion of fuel” within requirement 1.2.2 to “fuel supply” to ensure consistency with the language used in requirement R2, 2.2.2.
The FRCC also would like to note that requirement 1.3.3 includes transmission constraints that limit the flow of MWs from the generator to the load in the ERA process and would require that a power flow study be performed for this constraint. This would add another level of complexity to the energy balancing study. The FRCC suggests removing the “delivery” language and instead should describe the constraints in terms of generator MW output ability.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

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

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance

Answer	No
Document Name	

Comment

The SRC supports and appreciates the direction taken by the Standard Drafting Team (SDT) to increase flexibility for BAs. While the SRC agrees that Draft #2 is an improvement over Draft #1, the SRC has identified ambiguities and areas for further improvement, and consequently proposes the following:

As an initial matter, it is not clear whether the language in Part 1.1 is addressing the time period being assessed or the amount of time entities must spend performing the assessment. It is also unclear whether the language requires entities to begin a new ERA within two days of each operating day, or whether the language simply limits how far in the future the ERA may look. To clarify these issues, the SRC recommends that the language be revised to read “The near-term ERA must assess a time period that is between three and six weeks long and that begins no later than two days after the operating day in which the responsible entity begins conducting the near-term ERA.”

The SRC also proposes revisions to Part 1.3.2, as follows: • Move “variable energy resources” and “electric storage” as examples to the Technical Rationale. It is misleading and incomplete for a standard to list a limited subset of resource technologies as examples, as it creates ambiguity regarding how other technologies should be addressed, particularly new technologies that are developed in the future. Standards should be limited to mandatory requirements; examples are more appropriately located in the Technical Rationale. • Replace the reference to “depletion of fuel” in Part 1.3.2 with “unplanned generator outages,” as this language will encompass all reasons leading to unplanned generator outages and not be limited to fuel supply alone. • Add the word “known” to resource capabilities and operations in Part 1.3.2 to avoid any ambiguity. • Pursuant to the above comments, the SRC suggests Part 1.3.2 be modified as shown below: 1.3.2. Known Rresource capabilities and operations, including energy supply, depletion of fuel supply, variable energy resources (e.g., wind, solar, and hydro), unplanned generator outages and energy transfers between neighboring Balancing Authorities, and electric storage; and Finally, the SRC recommends removing Part 1.3.3, as Part 1.3.2 already includes ‘resource capabilities,’ which would take into account transmission limitations. If the SDT elects to keep Part 1.3.3., the SRC recommends that it be revised as follows: 1.3.3. Reasonably foreseeable TtransmissionGeneration that is available but its Electrical Energy cannot be delivered to the point of interconnection or Balancing Authority Area due to one or more reasonably foreseeable transmission outage. constraints outages that bottle generation and limit the ability deliverability of generator’s ion to deliver their output. to load.]	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
APS is of the opinion that while documenting and maintaining a process for conducting near-term ERAs is viable, performing near-term ERAs between five days and six weeks as prescribed in BAL-007-1 Draft 2 R1.1, would be difficult to perform by the Balancing Authority due to varying data inputs required, challenging to continuously manage, and may create significant administrative burden without increasing reliability. The Balancing Authority should not be required to study time periods that are not of concern or at risk simply to meet a requirement to perform an assessment.	

To be succinct, the requirement language and support the scope of the SAR , the SDT should consider revising BAL-007-1 R1 and subparts with the following italicized proposals:

- R1.1 replace what is currently written to: *The time periodicity for near-term ERAs shall be defined by the Balancing Authority according to its risks to the BPS.* (As defined in the Project Scope of the ERATF SAR “Energy Assessments with Energy–Constrained Resources in the Operations and Operations Planning Time Horizons”, pp. 3-4.)
- R1.3.1 removing "assumed" resulting in “*Forecasted Demand Profiles*.
- R1.3.2 revising to "*Resource capability and deliverability*. "
- R1.3.3 revising to "*Transmission constraints that limit generation output deliverability to load.*

Lastly, APS agrees with EEI’s comments and proposal of changing “depletion of fuel” within subpart 1.2.2 to “fuel supply” to ensure consistency with the language used in Requirement R2, subpart 2.2.2.

Likes 0	
Dislikes 0	
Response	
LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

Seminole agrees with FRCC’s comments below

The FRCC believes that BAL-007 R1 does not appear to allow BAs to generate a region-wide ERA, based on the common practice of sharing of resources, coordinated generation resource dispatch, or Reserve Sharing Groups.
The FRCC believes there is no has been no allowance given to Resource Planners and/or BAs who may decide to complete these requirements through cooperative resource programs and that the proposed changes do not allow for BAs who have coordinated together on a region-wide Capacity and Energy Emergency Plan to use these plans for these requirements. These plans ensure that each BA throughout the region has taken all possible steps to avoid a declared Energy Emergency (EEA 2/3) or a capacity issue that could ultimately result in the shedding of Firm Native Customer Load. The requirement for each BA to create BA-specific ERAs could result in the lack of proper coordination between BAs and create a bigger risk to the

interconnected Bulk Electric System.
The FRCC does not support the language in requirement 1.2.1 because it does not allow a BA the flexibility to determine the duration and frequency of performing an ERA and that performing studies to cover all time periods is extremely burdensome. It would be better for the BA to assess what time periods need to be covered based on their area and define that within their process. and defined scenarios.
As proposed, this requirement would disproportionately increase the administrative burden without increasing reliability.
The FRCC also proposes changing “depletion of fuel” within requirement 1.2.2 to “fuel supply” to ensure consistency with the language used in requirement R2, 2.2.2.
The FRCC also would like to note that requirement 1.3.3 includes transmission constraints that limit the flow of MWs from the generator to the load in the ERA process and would require that a power flow study be performed for this constraint. This would add another level of complexity to the energy balancing study. The FRCC suggests removing the “delivery” language and instead should describe the constraints in terms of generator MW output ability.

Likes 0	
Dislikes 0	

Response

Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6

Answer	No
Document Name	

Comment

The standard should be updated to allow for compliance through individual actions or participation in a Resource Adequacy or equivalent program similar to Frequency Response Sharing Group and Reserve Sharing Groups. Puget Sound Energy agrees with WPP’s response to this question, shown below.

As written, BAL-007 R1 does not appear to allow BAs to collectively pool resources to produce regional or sub-regional ERAs. No flexibility or deference is given to Resource Planners and entities who elect to do these tasks under programs like the Western Resource Adequacy Program in the Western Power Pool. The language used doesn’t provide flexibility for entities who have committed to sub-regional energy emergency plans, either. These plans are developed to ensure, prior to a declared EEP, that each entity in the sub-region has taken all action possible to avoid an energy or capacity issue. Perhaps the Drafting Team’s intent is to codify that BAs, Regions or sub-regions must have such plans, but the requirement does not clearly state this. The largest risk to requiring individual BAs to create independent ERAs is that they will not be coordinated with other BAs, and they may be reliant on erroneous assumptions of available mutual assistance or market access.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	No
Document Name	

Comment

USV supports the comments provided by MISO.

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy supports and appreciates the direction taken by the Standard Drafting Team (SDT) to increase flexibility for BAs. While we agree Draft #2 is an improvement over Draft #1, we propose the following:

Modify Part 1.3.2. to align with Part 2.2

{C}· Replace “depletion of fuel” with “fuel supply.” (Part 2.2.)

{C}o “Depletion of fuel” is overly prescriptive and one-sided (fails to consider replenishment) whereas “fuel supply” allows for a broad consideration of all fuel supply factors without requiring the BA to maintain documentation specific to the *depletion* of fuel for each generating resource.

{C}· Move “variable energy resources” and “electric storage” as examples to the Technical Rationale. It is misleading and incomplete for a standard to list a limited subset of resource technologies simply because they are “new.” There will be other technologies in the future. Examples are more appropriately located in the Technical Rationale.

{C}· Add “unplanned generator outages” to Part 1.3.2 as this language will encompass all reasons leading to “unplanned generator outages/de-rates” and not limit it to fuel supply alone.

{C}· Pursuant to the above comments, we suggest **Part 1.3.2** be modified as shown below:

1.3.2. Known Resource capabilities and operations, including energy supply, fuel supply, unplanned generator outages and energy transfers between neighboring Balancing Authorities; and

- Since Part 1.3.2 includes ‘resource capabilities,’ that should encompass transmission limitations. Therefore, NV Energy requests **Part 1.3.3 be stricken.** If the SDT disagrees with removing Part 1.3.3. altogether, then NV Energy proposes the following modification:

1.3.3. Transmission outages that bottle generation and limit the generator’s output ability.

Likes 0	

Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not support the language in subpart 1.2.1 because it does not allow the BA the flexibility to determine the duration and frequency of performing an ERA. Performing studies to cover all time periods does not increase reliability. The BA should not be required to study time periods that are not of concern simply to meet a requirement to perform studies. As proposed this requirement would disproportionately increase the administrative burden without increasing reliability.

We also proposed changing “depletion of fuel” within subpart 1.2.2 to “fuel supply” to ensure consistency with the language used in Requirement R2, subpart 2.2.2.

EEI additionally notes that in subpart 1.3.3, it includes transmission constraints that limit the flow of MWs from the generator to the load in the ERA process indicates that a power flow study is expected to be performed. This would add more complexity to what is intended to be an energy balancing study. To address this concern, we suggest removing the “delivery” language and instead describe constraints in terms of generator MW output ability.

To address our Requirement R1 concerns we have included edits in boldface below:

R1. Each Balancing Authority shall document and maintain a process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. The near-term ERA shall be performed within **a** time period of **two** days **but no more than** six weeks **out from Real-time**.

1.2. The frequency **and duration** of near-term ERA**s shall be as defined by the responsible BA, utilizing the BA’s knowledge and experience of their BA Area to address conditions and forecasted events that they determine to be risks to BPS reliability.**

1.3. The ERA process for near-term ERAs must account for the following:

1.3.1. Forecasted or assumed Demand profiles;

1.3.2. Resource capabilities and operations, including fuel **supply**, variable energy resources (e.g., wind, solar, and hydro), energy transfers between neighboring Balancing Authorities, and electric storage; and

1.3.3. **Local known BES transmission** constraints that limit the ability of **a generator to output expected MWs**.

Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	No

Document Name	

Comment

While ISO-NE believes the current version of R1 to be sufficient there are some potential edits to clarify or simplify aspects of the Requirement

ISO-NE supports CAISO's suggestion to expand the ERA duration to between three days and six weeks to provide additional flexibility to BAs.

Suggested revisions:

R1.1 should be two separate sub requirements and clarify that the period listed is the assessment period:

1.1 The near-term ERA must include an assessment period of between five days and six weeks.

1.2 The near-term ERA shall begin no later than two days after the present operating day.

Current 1.2-1.4 will need to be renumbered.

R1.3.1 Forecasted demand profiles

Forecasted demand profiles are already based on assumptions

R1.3.2 Change "depletion of fuel" to "fuel supplies"

Likes 0	
Dislikes 0	

Response

Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	

Comment

The standard should be updated to allow for compliance through individual actions or participation in a Resource Adequacy or equivalent program similar to Frequency Response Sharing Group and Reserve Sharing Groups. Puget Sound Energy agrees with WPP's response to this question, shown below.

As written, BAL-007 R1 does not appear to allow BAs to collectively pool resources to produce regional or sub-regional ERAs. No flexibility or deference is given to Resource Planners and entities who elect to do these tasks under programs like the Western Resource Adequacy Program in the Western Power Pool. The language used doesn't provide flexibility for entities who have committed to sub-regional energy emergency plans, either. These plans are developed to ensure, prior to a declared EEP, that each entity in the sub-region has taken all action possible to avoid an energy or capacity issue. Perhaps the Drafting Team's intent is to codify that BAs, Regions or sub-regions must have such plans, but the requirement does not clearly state this. The largest risk to requiring individual BAs to create independent ERAs is that they will not be coordinated with other BAs, and they may be reliant on erroneous assumptions of available mutual assistance or market access.

Likes 0	
Dislikes 0	

Response	
Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	No
Document Name	
Comment	
We suggest adding verbiage that allows some flexibility in the data requested: For example, we suggest the following (underlined) addition to R1.3.2 : Resource capabilities and operations, including pertinent data such as depletion of fuel variable energy resources (e.g., wind, solar, and hydro), energy transfers between neighboring Balancing Authorities, and electric storage;	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Resource Adequacy is typically addressed by Resource Planners. The definition of a Resource Planner is one year and beyond but the current wording of this standard is more in line with what Resource Planners responsibilities.	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1,3

Answer	No
Document Name	

Comment

Exelon supports EEI's comments suggesting greater flexibility.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the Western Power Pool comments.

Additionally, the timing requirement in BAL-007-1 R1 is still confusing and unrealistic. Tacoma Power recommends instead of specifying a start (five days) and end time (six weeks), that BAL-007-1 R1 leave the evaluation period flexible. The evaluation time period may be different for each BA and have different timing considerations. If a specific timeline is kept in BAL-007-1 R1, then Tacoma Power requests a visual aid in the technical rationale to understand how the ERA timing overlaps with the TOP-001 and TOP-002 analyses.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2

Likes 0	

Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

For section 1.3.2 it is recommended that:

- replace “depletion of fuel” with “fuel supply"
- move “variable energy resources” and “electric storage” to the Technical Rationale.
- Add “unplanned generator outages”

Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

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

Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	

Manitoba Hydro supports comments of MRO NSRF.

Likes 0	

Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	

Ameren supports MISO's comments on this project.

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

As written, BAL-007 R1 does not appear to allow BAs to collectively pool resources to produce regional or sub-regional ERAs. No flexibility or deference is given to Resource Planners and entities who elect to do these tasks under programs like the Western Resource Adequacy Program in the Western Power Pool. The language used doesn't provide flexibility for entities who have committed to sub-regional energy emergency plans, either. These plans are developed to ensure, prior to a declared EEA, that each entity in the sub-region has taken all action possible to avoid an energy or capacity issue. Perhaps the Drafting Team's intent is to codify that BAs, Regions or sub-regions must have such plans, but the requirement does not clearly state this. The largest risk to requiring individual BAs to create independent ERAs is that they will not be coordinated with other BAs, and they may be reliant on erroneous assumptions of available mutual assistance or market access.

The BA, as identified in the current draft of BAL-007, is the wrong function to address resources adequacy. The Resource Planner, as defined in the NERC ROP and NERC Glossary of Terms Used in the Reliability Standards, is the most appropriate functional entity to conduct ERAs. Arguably, the Resource Planner generally focuses on resource adequacy on "a long-term (generally [emphasis added] one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area", but not on a short-term plan. It is the Resource Planner's responsibility to "[Coordinate] with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans" (see NERC Functional Model). BAs are not typically staffed with planners who are familiar with assessing resource adequacy, and they rely on assessments from Resource Planners, Transmission Planners, and the Load-Serving Entities to develop their Operating Plans regarding such things as energy capacity and fuel availability.

Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	

TEPC agrees with EEI's comments - EEI does not support language that does not allow the BA the flexibility to determine the duration and frequency of performing an ERA. Performing studies to cover all time periods does not increase reliability. The BA should not be required to study time periods that are not of concern simply to meet a requirement to perform studies. This requirement would disproportionately increase the administrative burden without increasing reliability.

Likes 0	
Dislikes 0	
Response	

Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	

Constellation has concerns on BAs developing their own process for lack of uniform requests to generator owners

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	

Southern Company supports the EEI comments and agrees with EEI's proposed language changes.

Likes 0	
Dislikes 0	

Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
CHPD supports the majority of WPP's response. CHPD suggests that in paragraph 1, EEP should be EEA.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI. EEI does not support the language in subpart 1.2.1 because it does not allow the BA the flexibility to determine the duration and frequency of performing an ERA. Performing studies to cover all time periods does not increase reliability. The BA should not be required to study time periods that are not of concern simply to meet a requirement to perform studies. As proposed this requirement would disproportionately increase the administrative burden without increasing reliability. We also proposed changing "depletion of fuel" within subpart 1.2.2 to "fuel supply" to ensure consistency with the language used in Requirement R2, subpart 2.2.2.	

We also additionally note that in subpart 1.3.3, it includes transmission constraints that limit the flow of MWs from the generator to the load in the ERA process indicates that a power flow study is expected to be performed. This would add more complexity to what is intended to be an energy balancing study. To address this concern, we suggest removing the "delivery" language and instead describe constraints in terms of generator MW output ability.

To address our Requirement R1 concerns we have included edits in boldface below:

R1. Each Balancing Authority shall document and maintain a process for conducting Energy Reliability Assessments (ERA) for the near-term time horizon. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. The near-term ERA *(remove: **must have a)*** shall be performed within (*remove:* ***the***) **a** time period of (*remove:* ***duration between five)*** **two** days (*remove:* ***and)*** **but no more than** six weeks **out from Real-time (***remove:* **and begin no later than two days after the present operating day)**.

1.2. The frequency **and duration** of near-term ERA**s shall be as defined by the responsible BA, utilizing the BA's knowledge and experience of their BA Area to address conditions and forecasted events that they determine to be risks to BPS reliability. (***remove:* ***must be at intervals that ensure all time periods are covered by a near-term ERA.)***

1.3. The ERA process for near-term ERAs must account for the following:

1.3.1. Forecasted or assumed Demand profiles;

1.3.2. Resource capabilities and operations, including (*remove:* ***depletion of***) fuel **supply**, variable energy resources (e.g., wind, solar, and hydro), energy transfers between neighboring Balancing Authorities, and electric storage; and

1.3.3. **Local (***remove:* ***Transmission*****) known BES transmission** constraints that limit the ability of (*remove:* ***generation to deliver their output to load***) **a generator to output expected MWs**.

Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
Please see BPA’s full response in question 9.	
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 recommended changes for BAL-007-1 R1.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion	
Answer	No
Document Name	
Comment	
While Dominion Energy supports EEI comments, we also are concerned that In sub requirement 1.3.1, usage of the NERC defined term “Demand” does not seem appropriate given the context within the requirement as Demand is not used for energy over time.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	

WEC Energy Group supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy

Answer	No
Document Name	

Comment

DTE supports MISO's feedback

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Duke Energy recommends the following modification to R1.3.3. to extend resources beyond the BA.

R1.3.3. "Known BES transmission constraints that limit the ability to utilize expected resources."

Additionally, Duke is supportive of EEI comments to leverage the operational experience of the BA, including the frequency of the ERA and not having to perform studies which encompass 'all time periods'. For instance, the BA, in the development of its near-term ERA process, may identify operational concerns as a tail risk condition requiring closer inspection via the documented ERA process.

Likes 0	
Dislikes 0	

Response

Reed Adam - Seattle City Light - 1,3,5,6 - WECC

Answer	No

Document Name	
Comment	

As written, BAL-007 R1 does not appear to allow BAs to collectively pool resources to produce regional or sub-regional ERAs. No flexibility or deference is given to Resource Planners and entities who elect to do these tasks under programs like the Western Resource Adequacy Program in the Western Power Pool. The language used doesn’t provide flexibility for entities who have committed to sub-regional energy emergency plans, either. These plans are developed to ensure, prior to a declared EEP, that each entity in the sub-region has taken all action possible to avoid an energy or capacity issue. Perhaps the Drafting Team’s intent is to codify that BAs, Regions or sub-regions must have such plans, but the requirement does not clearly state this. The largest risk to requiring individual BAs to create independent ERAs is that they will not be coordinated with other BAs, and they may be reliant on erroneous assumptions of available mutual assistance or market access.
The BA, as identified in the current draft of BAL-007, is the wrong function to address resources adequacy. The Resource Planner, as defined in the NERC ROP and NERC Glossary of Terms Used in the Reliability Standards, is the most appropriate functional entity to conduct ERAs. Arguably, the Resource Planner generally focuses on resource adequacy on “a long-term (generally [emphasis added] one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area”, but not on a short-term plan. It is the Resource Planner’s responsibility to “[Coordinate] with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans” (see NERC Functional Model). BAs are not typically staffed with planners who are familiar with assessing resource adequacy, and they rely on assessments from Resource Planners, Transmission Planners, and the Load-Serving Entities to

Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

SCL is in support and alignmnet with WPP's & Idaho's submitted comments.

Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

I agree with the comments provided by Western Power Pool.

Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seattle City Light agrees with WPP Submitted Comment.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

Idaho Power agrees with WPP's response to this question, shown below.

As written, BAL-007 R1 does not appear to allow BAs to collectively pool resources to produce regional or sub-regional ERAs. No flexibility or deference is given to Resource Planners and entities who elect to do these tasks under programs like the Western Resource Adequacy Program in the Western Power Pool. The language used doesn't provide flexibility for entities who have committed to sub-regional energy emergency plans, either. These plans are developed to ensure, prior to a declared EEP, that each entity in the sub-region has taken all action possible to avoid an energy or capacity issue. Perhaps the Drafting Team's intent is to codify that BAs, Regions or sub-regions must have such plans, but the requirement does not clearly state this. The largest risk to requiring individual BAs to create independent ERAs is that they will not be coordinated with other BAs, and they may be reliant on erroneous assumptions of available mutual assistance or market access.

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Likes 0	
Dislikes 0	

Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
WECC generally supports the proposed revision but offers the following for clarity. Suggest for clarification for R1- Drop the phrase “for the near-term time horizon” and add “near-term” after “conducting”. Also add “s” to “ERA”. “Each Balancing Authority shall document and maintain a process for conducting near-term Energy Reliability Assessments (ERAs).” This edit will remove the efforts to determine what the “near-term time horizon” may be by industry and CMEP staff. Suggest for clarification 1.2 Remove “are” and add “will be”. Also add “s” to first use of ERA. “The frequency of near-term ERAs must be at intervals that ensure all time periods will be covered by a near-term ERA.” Saying “all” and “are” appear to go beyond the expectations of near-term ERA and may not be bounded by the duration of the evaluation period. In 1.3.2, it is not clear what is meant by “and operations”. Is the DT trying to capture projected availability of resources? Suggest “Resource capabilities and availability including variable energy resource (e.g., wind, solar, hydro); Fuel supply concerns and inventory; energy transfers between neighboring Balancing Authorities; and electric storage; and”. Should “electric storage” be BESS for consistency across Standards? Consider addressing hydro/wind/solar in the technical rationale to avoid limitations on future technologies.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	
Document Name	
Comment	
BC Hydro appreciates the direction the drafting team has taken in allowing more flexibility for BAs.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO answers "No." (We had difficulty entering our comments into the SBS.)

MISO supports and appreciates the direction taken by the Standard Drafting Team (SDT) to increase flexibility for BAs. While MISO agrees that Draft #2 is an improvement over Draft #1, MISO has identified ambiguities and areas for further improvement, and consequently proposes the following:

As an initial matter, it is not clear whether the language in Part 1.1 is addressing the time period being assessed or the amount of time entities must spend performing the assessment. It is also unclear whether the language requires entities to begin a new ERA within two days of each operating day, or whether the language simply limits how far in the future the ERA may look. To clarify these issues, MISO recommends that the language be revised to read “The near-term ERA must assess a time period this is between five days and six weeks long and that begins no later than two days after the operating day in which the responsible entity begins conducting the near-term ERA.”

MISO also proposes revisions to Part 1.3.2, as follows:

- Replace “depletion of fuel” with “fuel supply.” (Part 2.2.) as “depletion of fuel” is overly prescriptive and one-sided since it fails to consider replenishment, whereas “fuel supply” allows for a broad consideration of all fuel supply factors without requiring the BA to maintain documentation specific to the *depletion* of fuel for each generating resource.
- Move “variable energy resources” and “electric storage” as examples to the Technical Rationale. It is misleading and incomplete for a standard to list a limited subset of resource technologies as examples, as it creates ambiguity regarding how other technologies should be addressed, particularly new technologies that are developed in the future. Standards should be limited to mandatory requirements; examples are more appropriately located in the Technical Rationale.
- Replace the reference to “depletion of fuel” in Part 1.3.2 with “unplanned generator outages,” as this language will encompass all reasons leading to unplanned generator outages and not be limited to fuel supply alone.
- Add the word **“known”** to resource capabilities and operations in Part 1.3.2 to avoid any ambiguity as shown below:**1.3.2**. ***Known*** Rresource capabilities and operations, including fuel supply, unplanned generator outages and energy transfers between neighboring Balancing Authorities, and
- Finally, remove **Part 1.3.3,** from the standard altogether as Part 1.3.2 already includes ‘resource capabilities,’ which would take into account transmission limitations. If the SDT elects to keep Part 1.3.3., revise it as follows:

1.3.3. Reasonably foreseeable transmission outages that limit the deliverability of generator output.

Likes 0	
Dislikes 0	

Response

3. BAL-007-1 Near-term ERAs: The SDT updated Requirements R2 through Requirement R8 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

Idaho Power agrees with WPP's response to this question, shown below.

R2: In general, R2 is vague and ambiguous. It amounts to a fill-in-the-blank standard. This puts entities in a position where they create their own standard to be audited against. This creates a situation where many companies will choose to meet minimum compliance thresholds to not risk potential non-compliance. Entities who may want to put their best effort forward will be reluctant to do that because it will have a higher risk of non-compliance. R2 has no performance measurements associated with it specifying a required minimum level of performance. NERC Standards should be performance based, not administrative. Documentation of Scenarios, methods, and rationales will result in subjective enforcement. Enforcement staff will likely leverage the ability to audit based on the quality of their ERA, not their performance to improve reliability.

Entities will be subject to compliance risks for administrative mistakes, rather than poor performance that results in actual risk to the BES. The drafting team is encouraged to consider what the minimal acceptable performance level should be for these assessments.

The Drafting Team utilizes the term "credible" several times. Credible is a very subjective term, and what is credible to one entity (or auditor), may not be credible to another. This leaves the entity in a very difficult situation when being audited against R2.

R3: R3 requires the BA to document and maintain one or more Operating Plans to minimize forecasted Energy Emergencies identified during the ERA, but it does not require implementation or effectiveness in avoiding an Energy Emergency. BAs maintain multiple Operating Plans under TOP-002, including identifying potential EEA situations. The Drafting Team it is not clear if their operating plans are the same or different Operating Plans generated TOP-002. If they are different, this is another set of plans that must be separately considered and coordinated. TOP-002 deals with next-day operations, it isn't clear if the proposed BAL-007 Operating Plans can, or cannot, be integrated with BA responsibilities under TOP-002.

R3 uses the phrase "...minimize forecasted Energy Emergencies..." this is subjective and not measurable. To what degree do the plans need to minimize? Though the intent of the drafting team seems clear, during enforcement it will be up to the interpretation of the auditor to determine if emergencies will be effectively minimized.

The measures in both R2 and R3 give little guidance to an entity, or the auditor, as to what evidence is sufficient to show performance. Measures are there to provide guidance to the entity on how they will be measured and parroting the requirement provides little-to-no-guidance. These two requirements are administrative and require generating documents for compliance, and they do not set a minimum criterion for performance. This encourages minimal compliance, not an acceptable level of performance.

R4: R4 requires the entity to review and update its near-term ERA process "if needed". There will be a burden on the entity to prove when updated is needed. During enforcement, if a document is not updated regularly, the auditor will assume it is not being maintained properly. Entities will be put in a position to explain why updates were not "needed". In these situations, auditors will look for errata errors in the documentation and argue that updating was, in fact, needed. This leads to a zero-defect compliance approach. NERC has been trying to distance itself from this type of enforcement through better written standards.

M4 continues to confuse the reader, because of the use of "as needed". M4 can be interpreted to exclude evidence if updates were determined to not be needed.

R5: In R5 the entities are asked to "...provide [their] near-term ERA process, Scenarios or methods, and Operating Plans(s)... to the RC at least once every 24 Calendar Months, on a mutually agreed schedule." R1 requires the need for the BAs to develop a process and R4 requires the process to be reviewed and updated at least once every 24 calendar months. R3 requires the entity to create Operating Plans based on the ERA process, these are done for time periods somewhere between 5 day and 6-week periods. The product from R3 is only relevant to the time period it is looking at. Requiring entities to provide the "...Scenarios or methods, and Operating Plans..." at least once

every 24 calendar months is confusing. The submission of the ERA process does make sense, since it is supposedly reviewed and updated in that period; however, Scenarios, methods and Operating Plans are of little use after the time they were completed for has passed. It is recommended that ONLY the updated ERA process be submitted to the RC every 24 calendar months.

The ERA process submission to the RC should require resubmission any time a revision is made to the process. If, as currently stated, an entity submits their plan to the RC, then updates the document, they are not obligated to send the RC the current version until the next cycle. Other NERC Standards have the entity submit the updated processes within 30 or 60 days of any update, or on schedules that are mutually agreed to with the RC and the entity.

R6: The lead in sentence of R6 is written passively, and not consistent with good standard writing structure. The responsible entity should be stated first, then followed by the actions or requirement. The Drafting Team should consider rewriting the first sentence consistent with the other requirements. Perhaps: "The Reliability Coordinator, within 60 days of receipt of the information identified in Requirement R5, shall:"

If R6 focuses on the ERA process and not the Scenarios, methods or Operating Plans, there is little need for the RC to evaluate the process for reliability risks. Under common practices, the RCs would typically collect the ERA process documentation and only use it if there is a question related to how a company may have identified an emerging condition. There should be little need to provide feedback to the entity on its process, and there is no need to complete a review and evaluation within 60 days. This then makes R7 unnecessary and will reduce administrative failures of the RC and BA.

R7: R7 is not necessary for just the submission of the ERA process.

R8: It isn't clear why the Drafting Team elected to put the implementation of R1 as one of the last requirements. R8 should be combined with R2 or R3 as a performance requirement following the R1 requirement. Alternatively, R8 could be moved up to R3, and renumbering the current requirements R3 through R7.

Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seattle City Light agrees with WPP Submitted Comment.	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 1,3,4,5,6	

Answer	No
Document Name	
Comment	

I agree with the comments provided by Western Power Pool.

Likes 0	
Dislikes 0	
Response	

Michael Jang - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	
Comment	

SCL is in support and alignmnet with WPP's & Idaho's submitted comments.

Likes 0	
Dislikes 0	
Response	

Reed Adam - Seattle City Light - 1,3,5,6 - WECC

Answer	No
Document Name	
Comment	

R2: In general, R2 is vague and ambiguous. It amounts to a fill-in-the-blank standard. This puts entities in a position where they create their own standard to be audited against. This creates a situation where many companies will choose to meet minimum compliance thresholds to not risk potential non-compliance. Entities who may want to put their best effort forward will be reluctant to do that because it will have a higher risk of non-compliance.
R2 has no performance measurements associated with it specifying a required minimum level of performance. NERC Standards should be performance based, not administrative. Documentation of Scenarios, methods, and rationales will result in subjective enforcement. Enforcement staff will likely leverage the ability to audit based on the quality of their ERA, not their performance to improve reliability.
Entities will be subject to compliance risks for administrative mistakes, rather than poor performance that results in actual risk to the BES. The drafting team is encouraged to consider what the minimal acceptable performance level should be for these assessments.
The Drafting Team utilizes the term "credible" several times. Credible is a very subjective term, and what is credible to one entity (or auditor), may not be credible to another. This leaves the entity in a very difficult situation when being audited against R2.
R3: R3 requires the BA to document and maintain one or more Operating Plans to minimize forecasted Energy Emergencies identified during the ERA, but it does not require implementation or effectiveness in avoiding an Energy Emergency. BAs maintain multiple Operating Plans under TOP-002, including identifying potential EEA situations. The Drafting Team it is not clear if their operating plans are the same or different Operating Plans generated TOP-002. If they are different, this is another set of plans that must be separately considered and coordinated. TOP-002 deals with next-day

operations, it isn't clear if the proposed BAL-007 Operating Plans can, or cannot, be integrated with BA responsibilities under TOP-002.
R3 uses the phrase "…minimize forecasted Energy Emergencies…" this is subjective and not measurable. To what degree do the plans need to minimize? Though the intent of the drafting team seems clear, during enforcement it will be up to the interpretation of the auditor to determine if emergencies will be effectively minimized.
The measures in both R2 and R3 give little guidance to an entity, or the auditor, as to what evidence is sufficient to show performance. Measures are there to provide guidance to the entity on how they will be measured and parroting the requirement provides little-to-no-guidance. These two requirements are administrative and require generating documents for compliance, and they do not set a minimum criterion for performance. This encourages minimal compliance, not an acceptable level of performance.
R4: R4 requires the entity to review and update its near-term ERA process "if needed". There will be a burden on the entity to prove when updated is needed. During enforcement, if a document is not updated regularly, the auditor will assume it is not being maintained properly. Entities will be put in a position to explain why updates were not "needed". In these situations, auditors will look for errata errors in the documentation and argue that updating was, in fact, needed. This leads to a zero-defect compliance approach. NERC has been trying to distance itself from this type of enforcement through better written standards.
M4 continues to confuse the reader, because of the use of "as needed". M4 can be interpreted to exclude evidence if updates were determined to not be needed.
R5: In R5 the entities are asked to "…provide [their] near-term ERA process, Scenarios or methods, and Operating Plans(s)… to the RC at least once every 24 Calendar Months, on a mutually agreed schedule." R1 requires the need for the BAs to develop a process and R4 requires the process to be reviewed and updated at least once every 24 calendar months. R3 requires the entity to create Operating Plans based on the ERA process, these are done for time periods somewhere between 5 day and 6-week periods. The product from R3 is only relevant to the time period it is looking at. Requiring entities to provide the "…Scenarios or methods, and Operating Plans…" at least once
every 24 calendar months is confusing. The submission of the ERA process does make sense, since it is supposedly reviewed and updated in that period; however, Scenarios, methods and Operating Plans are of little use after the time they were completed for has passed. It is recommended that ONLY the updated ERA process be submitted to the RC every 24 calendar months.
The ERA process submission to the RC should require resubmission any time a revision is made to the process. If, as currently stated, an entity submits their plan to the RC, then updates the document, they are not obligated to send the RC the current version until the next cycle. Other NERC Standards have the entity submit the updated processes within 30 or 60 days of any update, or on schedules that are mutually agreed to with the RC and the entity.
R6: The lead in sentence of R6 is written passively, and not consistent with good standard writing structure. The responsible entity should be stated first, then followed by the actions or requirement. The Drafting Team should consider rewriting the first sentence consistent with the other requirements. Perhaps: "The Reliability Coordinator, within 60 days of receipt of the information identified in Requirement R5, shall:"
If R6 focuses on the ERA process and not the Scenarios, methods or Operating Plans, there is little need for the RC to evaluate the process for reliability risks. Under common practices, the RCs would typically collect the ERA process documentation and only use it if there is a question related to how a company may have identified an emerging condition. There should be little need to provide feedback to the entity on its process, and there is no need to complete a review and evaluation within 60 days. This then makes R7 unnecessary and will reduce administrative failures of the RC and BA.
R7: R7 is not necessary for just the submission of the ERA process.
R8: It isn't clear why the Drafting Team elected to put the implementation of R1 as one of the last requirements. R8 should be combined with R2 or R3 as a performance requirement following the R1 requirement. Alternatively, R8 could be moved up to R3, and renumbering the current requirements R3 through R7.

Likes 0	
Dislikes 0	

Response

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy supports proposed EEI language modifications for R2.3, R3 and R6.

Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	No
Document Name	
Comment	

1. Requirement R2 uses the terms "credible" and "best" which are subjective and therefore not conducive to a measurable compliance assessment at audit. BC Hydro recommends revising to eliminate reliance on these terms.

2. Requirement R3 uses the term "minimize", which can be subject to interpretation. BC Hydro recommends using "mitigate" instead, similar to the existing language in EOP-011 R2.

3. Requirement R4 mandates a 24 calendar months to review and update as necessary the R1 process, R2 Scenarios/methods, and R3 Operating Plan(s). This may constitute double-jeopardy, as failure to review and/or update may also constitute a possible noncompliance to the requirement to "maintain" the R1, R2, and R3 deliverables. BC Hydro recommends that R4 is not required, rather a measure of compliance be added in conjunction with the requirement to maintain under R1, R2, and R3.

4. Requirement R5 as written is vague and does not seem to provide value to reliability, particularly in case of Operating Plans, many of which would be obsolete on a 24-month provision timeframe. The Technical Rationale indicates that the intent is for the BAs and their respective RCs to have a mutually agreed protocol for the BC to provide updated R1, R2 and R3 documentation to the RC. BC Hydro recommends that R5 be revised to reflect the intent as stated in the Technical Rationale. Suggested wording provided below:

“R5 Each Balancing Authority and RC shall have and implement a documented protocol for the Balancing Authority to provide, at least once every 24 calendar months, its Reliability Coordinator with the near-term ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3.”

5. Given the overlap with EOP-011, BC Hydro recommends that the BAL-007 requirements be better align with the existing EOP-011 Requirements as existing EOP-011 based processes can be utilized to accommodate the net new requirements pertinent to ERAs.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

See comments below in questions 4 and 7

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion supports EEI comments but, in addition, For R2, usage of the word “credible” is subjective. This requirement should make clear that credibility of the Scenarios is for the BA to define and document. This language is pulled straight from the technical rationale for BAL-007-1. Recommend addition of “BA to define credible within their process”.

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 recommended changes for BAL-007-1 R2, R3, and R6.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA’s full response in question 9.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	

Eversource supports the comments of EEI.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 1,3,5,6

Answer	No
Document Name	

Comment

Black Hills Corporation is aligned with EEI as stated below. EEI does not oppose the changes made to Requirements R4, R5, R7 and R8 but we do have concerns with the proposed changes to Requirements R2, R3 and R6.

Requirement R2 Concerns: EEI does not support language contained in subpart 2.3 because the BA should have sole authority to determine what constitutes "other scenarios with a credible risk". We additionally do not agree that it is necessary to include "or historical" within subpart 2.3 because the BA already has awareness of the historical risks within their BA region and those risk factors would be factored into their assessment of what is a credible risk. To address our concerns, we offer the following changes to Requirement R2, subpart 2.3 (in boldface):

2.3. Other Scenarios with a credible (*remove:* ***or historical***) risk of occurring (*remove:* ***based on the best information available at the time of Scenario creation***) **as determined by the BA**.

Requirement R3 Concerns: While EEI appreciates the intent of the proposed language to minimize forecasted Energy Emergencies, we are concerned that the proposed language provides no clarity regarding this process. To address this concern, we suggest including language that makes it clear that the BA has sole discretion regarding when it is necessary to notify the RC of forecasted Energy Emergencies. Such discretion would rightly provide due weight to the technical expertise of the BA allowing that functional entity to recognize when there is an imminent risk to the reliability of the BES and when it would be necessary to issue a notification under this Requirement.

R3: Each Balancing Authority shall document and maintain one or more Operating Plan(s) (*remove:* ***to minimize forecasted Energy Emergencies***) as identified in the near-term ERA (*remove:* ***, including***) **that include** provisions for notifying the Reliability Coordinator of **a** forecasted Energy Emergency (*remove:* ***and the Operating Plan(s)***), **when deemed necessary**. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Requirement R6 Concerns: EEI notes that Requirement R6 cites certain RC actions related to Requirement R5. Requirement R5 is an administrative Requirement that simply obligates the BA to supply their near-term ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. While Requirement R6 obligates the RC to review the R5 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days this is administrative and therefore should not have a VRF higher than Low. We note the following from the VRF Justification document:

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.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

LG&E & KU agree with comments provided by EEI.

Likes 0	
Dislikes 0	

Response

Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group

Answer	No
Document Name	

Comment

CHPD supports WPP’s response.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment	
Southern Company supports the EEI comments and has the same concerns for R2, R5, and R6.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
TEPC agrees with EEI's comments - EEI's concerns with the proposed changes to Requirements R2 (EEI does not support language contained in subpart 2.3 because the BA should have sole authority to determine what constitutes "other scenarios with a credible or historical risk".), R3 (While EEI appreciates the intent of the proposed language to minimize forecasted Energy Emergencies, we are concerned that the proposed language provides no clarity regarding this process. To address this concern, we suggest that simply including language that makes it clear that the BA has sole discretion regarding when it is necessary to notify the RC of forecasted Energy Emergencies would be sufficient.), and R6 (EEI notes that Requirement R6 cites certain RC actions related to Requirement R5. Requirement R5 is an administrative Requirement that simply obligates the BA to supply their near-term ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. While Requirement R6 obligates the RC to review the R5 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days this is administrative and therefore should not have a VRF higher than Low.).	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
R2: In general, R2 is vague and ambiguous. It amounts to a fill-in-the-blank standard. This puts entities in a position where they create their own standard to be audited against. This creates a situation where many companies will choose to meet minimum compliance thresholds to not risk potential non-compliance. Entities who may want to put their best effort forward will be reluctant to do that because it will have a higher risk of non-compliance. R2 has no performance measurements associated with it specifying a required minimum level of performance. NERC Standards should be performance based, not administrative. Documentation of Scenarios, methods, and rationales will result in subjective enforcement. Enforcement staff will likely leverage the ability to audit based on the quality of their ERA, not their performance to improve reliability.	

Entities will be subject to compliance risks for administrative mistakes, rather than poor performance that results in actual risk to the BES. The drafting team is encouraged to consider what the minimal acceptable performance level should be for these assessments.

The Drafting Team utilizes the term “credible” several times. Credible is a very subjective term, and what is credible to one entity (or auditor), may not be credible to another. This leaves the entity in a very difficult situation when being audited against R2.

R3: R3 requires the BA to document and maintain one or more Operating Plans to minimize forecasted Energy Emergencies identified during the ERA, but it does not require implementation or effectiveness in avoiding an Energy Emergency. BAs maintain multiple Operating Plans under TOP-002, including identifying potential EEA situations. The Drafting Team it is not clear if their operating plans are the same or different Operating Plans generated TOP-002. If they are different, this is another set of plans that must be separately considered and coordinated. TOP-002 deals with next-day operations, it isn’t clear if the proposed BAL-007 Operating Plans can, or cannot, be integrated with BA responsibilities under TOP-002.

R3 uses the phrase “…minimize forecasted Energy Emergencies…” this is subjective and not measurable. To what degree do the plans need to minimize? Though the intent of the drafting team seems clear, during enforcement it will be up to the interpretation of the auditor to determine if emergencies will be effectively minimized.

The measures in both R2 and R3 give little guidance to an entity, or the auditor, as to what evidence is sufficient to show performance. Measures are there to provide guidance to the entity on how they will be measured and parroting the requirement provides little-to-no-guidance. These two requirements are administrative and require generating documents for compliance, and they do not set a minimum criterion for performance. This encourages minimal compliance, not an acceptable level of performance.

R4: R4 requires the entity to review and update its near-term ERA process “if needed”. There will be a burden on the entity to prove when updated is needed. During enforcement, if a document is not updated regularly, the auditor will assume it is not being maintained properly. Entities will be put in a position to explain why updates were not “needed”. In these situations, auditors will look for errata errors in the documentation and argue that updating was, in fact, needed. This leads to a zero-defect compliance approach. NERC has been trying to distance itself from this type of enforcement through better written standards.

M4 continues to confuse the reader, because of the use of “as needed”. M4 can be interpreted to exclude evidence if updates were determined to not be needed.

R5: In R5 the entities are asked to “…provide [their] near-term ERA process, Scenarios or methods, and Operating Plans(s)… to the RC at least once every 24 Calendar Months, on a mutually agreed schedule.” R1 requires the need for the BAs to develop a process and R4 requires the process to be reviewed and updated at least once every 24 calendar months. R3 requires the entity to create Operating Plans based on the ERA process, these are done for time periods somewhere between 5 day and 6-week periods. The product from R3 is only relevant to the time period it is looking at. Requiring entities to provide the “…Scenarios or methods, and Operating Plans…” at least once every 24 calendar months is confusing. The submission of the ERA process does make sense, since it is supposedly reviewed and updated in that period; however, Scenarios, methods and Operating Plans are of little use after the time they were completed for has passed. It is recommended that ONLY the updated ERA process be submitted to the RC every 24 calendar months.

The ERA process submission to the RC should require resubmission any time a revision is made to the process. If, as currently stated, an entity submits their plan to the RC, then updates the document, they are not obligated to send the RC the current version until the next cycle. Other NERC Standards have the entity submit the updated processes within 30 or 60 days of any update, or on schedules that are mutually agreed to with the RC and the entity.

R6: The lead in sentence of R6 is written passively, and not consistent with good standard writing structure. The responsible entity should be stated first, then followed by the actions or requirement. The Drafting Team should consider rewriting the first sentence consistent with the other requirements. Perhaps: “The Reliability Coordinator, within 60 days of receipt of the information identified in Requirement R5, shall:”

If R6 focuses on the ERA process and not the Scenarios, methods or Operating Plans, there is little need for the RC to evaluate the process for reliability risks. Under common practices, the RCs would typically collect the ERA process documentation and only use it if there is a question related to how a company may have identified an emerging condition. There should be little need to provide feedback to the entity on its process, and there is no need to complete a review and evaluation within 60 days. This then makes R7 unnecessary and will reduce administrative failures of the RC and BA.

R7: R7 is not necessary for just the submission of the ERA process.

R8: It isn't clear why the Drafting Team elected to put the implementation of R1 as one of the last requirements. R8 should be combined with R2 or R3 as a performance requirement following the R1 requirement. Alternatively, R8 could be moved up to R3, and renumbering the current requirements R3 through R7.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	No
Document Name	

Comment

WECC is concerned that:

R2- The phrase "by a sufficient amount to stress the system within a range of credible situations" is ambiguous and will be applied inconsistently. Is varying conditions for an ERA intended to be sufficient enough to create an EEA level? There needs to be clarity in what may be expected in the rationales. Suggest "Include a rationale for the Scenarios or method of Scenario creation that includes support for criteria determined by the Balancing Authority for varying the following conditions." Suggest changing "operations" in R2.2. to "availability". Requirement 2.3 does not appear to be cohesive with the phrase "shall vary one or more of the following conditions…" Consider editing and adding as a second sentence in R2 as follows "Each Balancing Authority shall……….for use in performing near-term ERAs. Scenarios with a credible or historical risk of occurring may be used based on the best information available at the time of Scenario creation." As written each BA would not have to "consider" the other Scenarios called out in 2.3 (as mentioned in the Technical Rational). The "Other Scenarios" may not be seen as a "following condition" which will cause confusion. The DT is correct in including previous historical Scenarios that stress the System as a basis for an ERA. Consider adding a 2.2.4 "Energy transfers between neighboring Balancing Authorities" to support 1.3 language.

R3-This appears duplicative to EOP-011 R2. EOP-011 R2 has the time horizon for a near-term ERA covered and does not require the source of determination for an Energy Emergency (which means an ERA is a possible source of determination.)

R4/R5- Clarity may be needed in terms of for development of the Scenarios and Operating Plans every 24 calendar months (and associated submittals). Are the Scenarios intended to illustrate what is actually used (e.g., forecasted versus assumed Demand) in the near-term ERA versus the data itself? Operating Plans may change based on the near-term ERA duration selected and the conditions forecasted for the duration. Again, some overlap in EOP-011 to consider here. EOP-011 R2 requires the BA to "maintain" the Operating Plans without mention of a timeframe. While nothing precludes a BA from providing an ERA derived Operating Plan from being provided to the RC, anytime a specific timeline is placed within a Requirement registered entities tend to set internal milestones accordingly. In essence a registered entity could be in "compliance" for providing the Operating Plan at least once every 24 calendar months but not support reliability by maintaining the plan more frequently (also possibly in noncompliance with EOP-011).

R6- EOP-011 has a 30 calendar day timeline for Operating Plans associated with Energy Emergencies and is in conflict with this Requirements 60 calendar days. Suggest say "results" versus "information". It is not clear how the RC will avoid risks. Is it reviewing the Operating Plans only? As noted, it would be reasonable to expect Operating Plans to fit the conditions noted in a near-term ERA which has a limited duration (up to six weeks). What Operating Plans would be provided and of what value would Operating plans be if 24 months old? The Operating Plans for a Energy Emergency are to be reviewed by the RC prior to implementation. If Operating Plans are only reviewed once every 24 months versus as developed (and updated) how could coordination occur? Additionally, may need to indicate "Notify the submitting Balancing Authority…" versus "each" in Part 6.2.

R7- While not in conflict with EOP-011, EOP-011 may set a timeframe for response that could exceed the 60 calendar days. What is the expectation for the DT as to how a BA will address the reliability risks? Especially if the reliability risk is a coordination issue? It appears that for coordination caused/resultant reliability risks the RC would need to clearly indicate actions so that there is not an infinite loop of actions and reactions. Also, by using "any" that means a BA could address only one and be compliant. If supporting reliability, the BA should address ALL the reliability risks identified. What recourse does a BA have if it cannot alleviate the risk?

R8- While implicit, perhaps it should be explicit that applicable Scenarios based on the conditions should be utilized. The Scenarios may be developed for conditional issues and updated accordingly) so not all the Scenarios would be used.

R10- There are extended metrics (24 hrs) associated with the timing of notification which does not appear to support reliability. EOP-011 has a 30-minute requirement to notify others in the RC footprint for an Energy Emergency.

For all these Requirements, the DT just needs to ensure that the overlap between BAL-007 and EOP-011 is either minimized or, at least, coordinated in terms of expectations to avoid confusion.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Ameren supports MISO's comments on this project.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1,3,5,6

Answer	No
Document Name	

Comment

Manitoba Hydro supports comments of MRO NSRF.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

Part 2.3: it is recommended to remove the use of "the best".

Eliminate duplication for the need of an Operating Plan from BAL-007 R3-R7 with EOP-011 R2-R4.

Align and standardize time requirements of BAL-007 and EOP-011. Specifically:

- BAL-007, R5 mandates a 24-month review period for Operating Plan(s) whereas EOP-011, R2 leaves it up to the BA's discretion.
- BAL-007, R6 mandates a 60-day RC review period whereas EOP-011, R3 requires a 30-day RC review period.
- BAL-007, R7 mandates a 60-day period during which the BA must address issues identified by the RC whereas EOP-011, R4 allows the RC to specify the time period.

Suggested language modifications:

R4. The Balancing Authority shall review and update, if necessary, its near-term ERA process Scenarios or methods documented under Requirements R1 through R3 at least once every 24 calendar months.

R5. Each Balancing Authority shall provide its near-term ERA process Scenarios or methods documented under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule.

R6. Within 60 calendar days of receipt of the information identified in Requirement R5, the Reliability Coordinator shall:

6.1. Review each submittal for coordination with other Balancing Authorities' in its Reliability Coordinator Area to avoid risks to Wide Area reliability; and

6.2. Notify each Balancing Authority of the results of its review and specifying any time frame for resubmittal if revisions are needed to address reliability risks.

R7. Each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to R6 and resubmit the updated information to its Reliability Coordinator within a time period specified by its Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power supports the MRO NSRF and Wester Power Pool comments.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1,3

Answer	No
Document Name	

Comment

Exelon supports the concerns stated in the EEI comments.

Likes 0	
Dislikes 0	

Response

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

Supporting EEI comments.

Likes 0	
Dislikes 0	

Response

Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	No
Document Name	

Comment

The use of the term “credible” is very subjective. This will create an issue for Registered Entities when the standard is being audited.

The requirement parts of R2 are typically scenarios that would be analyzed by Resource Planners for longer term. What is meant by “credible energy supply contingency”? This is subjective and could be analyzed differently based on the person performing the ERA.

For R2.3, how does a Registered Entity prove to an auditor that other scenarios (if any) were available at the time of the Scenario creation?

For R4, the requirement to review and update its near-term ERA process if needed places undue burden on an entity to provide “proof to negative”. During an audit, this leaves too much open to interpretation for an auditor.

For R8, this requirement to perform the ERAs according to your process should be combined with R2 or R3 or moved up into the standard.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	No
Document Name	
Comment	

Comment applicable to all requirements: We suggest the usage of “resource” instead of “fuel” in all requirements, as it is more inclusive and covers cases when all generation is hydraulic.

R4 : This requirement seems redundant with the obligation in R4 which requires the BA to review and update if necessary the documentation requested in R1, R2 and R3,where the BA has the obligation to “maintain” Scenarios, methods and Operating Pans. In our opinion, to maintain the documentation implies that it is kept at a particular level by reviewing it when necessary.

R5, R6 and R7 : Are these requirements applicable when the same entity is the only RC and BA of it’s Interconnexion? If not, we would suggest adding language to these requirements to clarify .

R8 : We suggest adding the verb “implement” to R1 and R2, which would thus render this requirement unnecessary. “R1 Each Balancing Authority shall document, and maintain and implement a process for conducting Energy Reliability Assessments …”

Likes 0	
Dislikes 0	
Response	

Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	

PSE generally agrees with WPP’s response to this question. Additional PSE comments are shown below.

R2: PSE would like there to be some guidance on what is an acceptable level of performance for the ERA. This is typically established at the RC or TPC level for transmission reliability levels and would give the BA better support for managing generation resources. There should be some objective reliability objective offered rather than leaving it up to each entity.

R3:   PSE doesn’t think that TOP-002 operating plans have balancing requirements, rather having transmission plans to deliver the energy to the load. The EOP standard is currently the only balancing operating plan for capacity emergencies and therefore is already covered. Having a separate operating plan for actions outside real time is confusing. The only things we can really do is deny/recall generation outages.

R4: PSE would prefer a review and update schedule provided and thinks it makes a lot of sense to require the review to follow the same schedule as the EOP review and update schedule since they are closely linked. Possibly state shall be updated as part of Emergency Operating Procedure review… or similar language.

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI does not oppose the changes made to Requirements R4, R5, R7 and R8 but we do have concerns with the proposed changes to Requirements R2, R3 and R6.

Requirement R2 Concerns: EEI does not support language contained in subpart 2.3 because the BA should have sole authority to determine what constitutes "other scenarios with a credible risk". We additionally do not agree that it is necessary to include "or historical" within subpart 2.3 because the BA already has awareness of the historical risks within their BA region and those risk factors would be factored into their assessment of what is a credible risk. To address our concerns, we offer the following changes to Requirement R2, subpart 2.3 (in boldface):

2.3. Other Scenarios with a credible risk of occurring **as determined by the BA**.

Requirement R3 Concerns: While EEI appreciates the intent of the proposed language to minimize forecasted Energy Emergencies, we are concerned that the proposed language provides no clarity regarding this process. To address this concern, we suggest including language that makes it clear that the BA has sole discretion regarding when it is necessary to notify the RC of forecasted Energy Emergencies. Such discretion would rightly provide due weight to the technical expertise of the BA allowing that functional entity to recognize when there is an imminent risk to the reliability of the BES and when it would be necessary to issue a notification under this Requirement.

R3: Each Balancing Authority shall document and maintain one or more Operating Plan(s) as identified in the near-term ERA **that include** provisions for notifying the Reliability Coordinator of **a** forecasted Energy Emergency, **when deemed necessary**. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Requirement R6 Concerns: EEI notes that Requirement R6 cites certain RC actions related to Requirement R5. Requirement R5 is an administrative Requirement that simply obligates the BA to supply their near-term ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. While Requirement R6 obligates the RC to review the R5 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days this is administrative and therefore should not have a VRF higher than Low. We note the following from the VRF Justification document:

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.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment
Expand Part 2.2. to include "energy transfers between neighboring BAs." This will align Part 2.2 with Part 1.3.2 as illustrated below. For more details, see our response to Question 1. as illustrated below: **2.2.** Known Resource capabilities and operations, including the following: **2.2.1.** The effects of a credible energy supply contingency; **2.2.2.** The effects of a credible fuel supply contingency; and **2.2.3.** Unplanned generator outages; and **2.2.4.** Energy transfers between neighboring Balancing Authorities **Part 2.3.** Eliminate the use of "the best." This will be difficult to prove in an audit. **2.3.** Other Scenarios with a credible or historical risk of occurring based on the best information available at the time of Scenario creation. **Eliminate or modify BAL-007 requirements R3-R7 to remove duplication with EOP-011 requirements R2-R4.** Since the goal of BAL-007 is to perform ERAs and provide the BA with more lead-time to address forecasted Energy Emergency Alerts (as defined in EOP-011, Attachment 1, Section B), **many BAs will likely modify and/or expand *existing* Operating Plan(s) to comply with BAL-007 *and* EOP-011 versus drafting new documents**. Consideration should also be given to aligning and standardizing proposed BAL-007 requirements R3-R7 with EOP-011 requirements R2-R4. Currently, they vary just enough to increase the potential for human error without adding value to the process. For example: {C}· BAL-007, R5 mandates a 24-month review period for Operating Plan(s) whereas EOP-011, R2 leaves it up to the BA's discretion. {C}· BAL-007, R6 mandates a 60-day RC review period whereas EOP-011, R3 requires a 30-day RC review period. {C}· BAL-007, R7 mandates a 60-day period during which the BA must address issues identified by the RC whereas EOP-011, R4 allows the RC to specify the time period. Aligning and standardizing BAL-007 with EOP-011 will: {C}· Enable a smooth transition from BAL-007 to TOP-002 to TOP-001 and EOP-011 {C}· Decrease the potential for human error and eliminate the possibility of double jeopardy NV Energy proposes the following modifications:

{C}· **BAL-007, R3** is duplicative of EOP-011, R2, Parts 2.2 and 2.2.1 as EOP-011 requires *"one or more …Operating Plan(s) to mitigate ... Energy Emergencies"* and *"notification to the RC."* To capture the balance of the intent, NV Energy Recommends a modification to EOP-011, Part 2.2.1. and eliminating R3 from BAL-007:

EOP-011, 2.2.1. Notification to its Reliability Coordinator of:

{C}§ The forecasted Energy Emergency and Operating Plan(s)

{C}§ Current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

{C}· **BAL-007, R4** duplicates parts of EOP-011, R2 as EOP-011, R2 already requires Operating Plan(s) to be maintained. Therefore, retain only that portion of BAL-007, R4 that is new, i.e. to update the near-term ERA process and Scenarios or methods only.

R4. The Balancing Authority shall review and update, if necessary, its near-term ERA process, and Scenarios or methods, documented under Requirements R1 through R3 at least once every 24 calendar months.

{C}· **BAL-007, R5** duplicates parts of EOP-011, R2 as EOP-011, R2 already requires Operating Plan(s) to be maintained. Therefore, retain only that portion of BAL-007, R5 that is new, i.e. to update the near-term ERA process and Scenarios or methods only.

R5. Each Balancing Authority shall provide its near-term ERA process, and Scenarios or methods, documented under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule.

{C}· **BAL-007, R6** duplicates parts of EOP-011, R3 as EOP-011, R3 already requires the RC to review Operating Plan(s).

{C}o **BAL-007, Part 6.1** is partially duplicative of EOP-011, Part 3.1.2 as EOP-011, Part 3.1.2 already requires coordination of Operating Plan(s) for Wide area reliability. There is no need to specify "ERA information" as this is already specified in R5.

{C}o **BAL-007, Part 6.2** is partially duplicative of EOP-011, Part 3.1.3 as EOP-011, Part 3.1.3 already requires the RC to notify each BA of the results of their review. Recommend the time frame for resubmittal align with EOP-011., Part 3.1.3.

R6. Within 60 calendar days of receipt of the information identified in Requirement R5, the Reliability Coordinator shall:

6.1. Review each submittal for coordination with other Balancing Authorities' in its Reliability Coordinator Area to avoid risks to Wide Area reliability; and

6.2. Notify each Balancing Authority of the results of its review and specifying any time frame for resubmittal if revisions are needed to address reliability risks.

{C}· BAL-007, R7 should mirror EOP-011, R4 as EOP-011, R4 already requires BAs to resubmit their Operating Plan(s) to the RC within the time period specified by the RC.

R7. Each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to R6 and resubmit the updated information to its Reliability Coordinator within a time period specified by its Reliability Coordinator.

Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	

Puget Sound Energy (PSE) generally agrees with WPP's response to this question. Additional PSE comments are shown below.

R2: PSE would like there to be some guidance on what is an acceptable level of performance for the ERA. This is typically established at the RC or TPC level for transmission reliability levels and would give the BA better support for managing generation resources. There should be some objective reliability objective offered rather than leaving it up to each entity.

R3: PSE doesn't think that TOP-002 operating plans have balancing requirements, rather having transmission plans to deliver the energy to the load. The EOP standard is currently the only balancing operating plan for capacity emergencies and therefore is already covered. Having a separate operating plan for actions outside real time is confusing. The only things we can really do is deny/recall generation outages.

R4: PSE would prefer a review and update schedule provided and thinks it makes a lot of sense to require the review to follow the same schedule as the EOP review and update schedule since they are closely linked. Possibly state shall be updated as part of Emergency Operating Procedure review… or similar language.

Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

Seminole agrees with FRCC's comments below

R2:
The FRCC believes that R2 is too vague, especially the term "Credible". The lack of a specific definition will force individual BAs to create their own standard to be audited against. This situation will have the opposite effect of what is intended. The focus will be on compliance and not on actual Resource Adequacy. Also, the BAs will have to account for compliance risks due to administrative errors, not for inadequate performance that creates a real risk to the BES. The FRCC suggests the drafting team define what the minimal acceptable performance level should be for these assessments and define what "Credible" is intended to address.
R3:
The FRCC acknowledges the intent of the proposed language to minimize forecasted Energy Emergencies, but still has concerns that the proposed language provides no improved clarity regarding this process. The FRCC suggests including language that makes it clear that the BA has sole discretion regarding when it is necessary to notify the RC of forecasted Energy Emergencies. Such discretion would rightly provide due weight to the technical expertise of the BA allowing that functional entity to recognize when there is an imminent risk to the reliability of the BES and when it would be necessary to issue a notification under this Requirement.
R4:
The FRCC is concerned about the requirement for BAs to review and update its near-term ERA process "if needed". This places an undue burden on BAs to determine when an update is needed. The concern is that if there is no periodic update/review of the document, it has not been evaluated to be "needed". An auditor could then interpret this as not being maintained properly. There will be an additional compliance burden, where BAs will be forced to explain why updates were not "needed".
R5:
The FRCC suggests that the ERA process submission to the RC should require resubmission any time a revision is made to the process and on a schedule that is mutually agreed upon between the RC and the BA, not to exceed 24 calendar months if no updates have been made to the current plan. As written, if a BA submits a plan to the RC and then updates the plan document, there is no requirement to send the RC the current version until the next cycle (up to 24 months). There are examples in other NERC Standards that have the entity submit the updated processes within a certain time period after an update, or on schedules that are mutually agreed to with the RC and the entity.

R6:
The FRCC agrees with and supports the Edison Electric Institute (EEI) severity risk comments on R6:
Requirement R6 Concerns: EEI notes that Requirement R6 cites certain RC actions related to Requirement R5. Requirement R5 is an administrative Requirement that simply obligates the BA to supply their near-term ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. While Requirement R6 obligates the RC to review the R5 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days this is administrative and therefore should not have a VRF higher than Low. We note the following from the VRF Justification document:
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.
R7:
The FRCC has no comments on R7.
R8:
The FRCC has no comments on R8.

Likes 0	
Dislikes 0	

Response

LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
APS recognizes the importance of Energy Reliability Assessments however BAL-007-1 is duplicative of NERC Standards and Requirements prescribed under existing NERC Standards EOP-011, TOP-002 and TOP-003 and should not be prescribed in BAL-007-1. The BAL-007-1 Standard should be provided as a Technical Rationale or a Guidance Document that Balancing Authorities may use as an implementation Reference Guide. APS is in the opinion that there are alternative approaches in development to meet the near-term ERA needs such as the Western Resource Adequacy Program, which supports a wide area effort to assess and address resource adequacy to ensure reliability across the west. The WRAP Operations Program Timeline BPM outlines high level activities and associated timing of those activities that occur for the period starting from seven days prior to Operating Day, and in this way, captures the near-term assessment required to ensure resource adequacy.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	No
Document Name	
Comment	
The SRC recommends the following revisions to Requirements R2 through R8: (footnote: SPP is a party to these comments however does not support the references about duplication with EOP-011 requirements. SPP supports the need for reporting ERA results in BAL-007 however there is lack of clarity between the BAL-007 and EOP-011 obligations.)	

The phrase “by a sufficient amount” in Requirement R2 is unnecessary and should be removed. This would better align the language in BAL-007-1 R2 with the language in BAL-008-1 R2.

Additionally, Part 2.3 appears to be unnecessary, as the same effect could be achieved by deleting Part 2.3 and inserting the “credible or historical risk of occurring” qualifier elsewhere in Requirement R2. If Part 2.3 is retained, it should be revised to eliminate the use of “the best.” This will be difficult to prove in an audit.

2.3. Other Scenarios with a credible or historical risk of occurring based on the best information available at the time of Scenario creation.

Eliminate BAL-007 requirements R3-R7 to remove duplication with EOP-011 requirements R2-R4. Since the goal of BAL-007 is to perform ERAs and provide the BA with more lead-time to address forecasted Energy Emergency Alerts (as defined in EOP-011, Attachment 1, Section B), it is unnecessary and duplicative for BAL-007 to include requirements addressing preparation for and management of emergencies because EOP-011 already covers this topic. To the extent that an ERA identifies previously unknown potential Energy Emergencies, EOP-011 already provides the necessary framework and obligations for BAs to modify or expand existing Operating Plan(s) to prepare for and minimize the likelihood of the potential emergency situation.

Consequently, proposed BAL-007 requirements R3-R7 should be deleted because they are substantively duplicative of EOP-011 requirements R2-R4 while simultaneously varying just enough to increase the potential for human error without improving system reliability. For example:

• BAL-007, R5 mandates a 24-month review period for Operating Plan(s) whereas EOP-011, R2 leaves it up to the BA’s discretion.

• BAL-007, R6 mandates a 60-day RC review period whereas EOP-011, R3 requires a 30-day RC review period.

• BAL-007, R7 mandates a 60-day period during which the BA must address issues identified by the RC whereas EOP-011, R4 allows the RC to specify the time period.

Removing BAL-007 R3 – R7 in recognition of EOP-011 will:

• Enable a smooth transition from BAL-007 to TOP-002 to TOP-001 and EOP-011, and

• Decrease the potential for human error, eliminate the possibility of double jeopardy, and reduce the risk that attempts to track and comply with similar-yet-disparate administrative requirements will overshadow the underlying reliability objective.

In further support of this recommendation, the SRC notes the following additional areas of overlap and modifications that would help reduce the amount of duplication iveness with EOP-011:

• BAL-007, R3 is duplicative of EOP-011, R2, Parts 2.2 and 2.2.1 as EOP-011 requires “one or more …Operating Plan(s) to mitigate ... Energy Emergencies” and “notification to the RC.” Additionally, it is unclear how an entity would demonstrate or how a Regional Entity would audit whether a forecasted emergency has truly been “minimized.” Consequently, Requirement R3 should be eliminated. A corresponding modification could be made to EOP-011, Part 2.2.1, but may be unnecessary given that that notification requirement in EOP-011 Part 2.2.1 falls under the process to prepare for Emergencies and is therefore not necessarily limited to active emergency conditions:

EOP-011, 2.2.1. Notification to its Reliability Coordinator of:

 The any forecasted Energy Emergenciesy and associated Operating Plan(s), and

 to include cCurrent and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

BAL-007: R3. Each Balancing Authority shall document and maintain one or more Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term ERA, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s).

• BAL-007, R4 duplicates parts of EOP-011, R2 as EOP-011, R2 already requires Operating Plan(s) to be maintained. Therefore, if R4 is retained, it should be revised to only address updates to the near-term ERA process and Scenarios or methods.

R4. The Balancing Authority shall review and update, if necessary, its near-term ERA process, and Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 at least once every 24 calendar months.

• BAL-007, R5 duplicates parts of EOP-011, R2 as EOP-011, R2 already requires Operating Plan(s) to be maintained. Therefore, if R5 is retained, it should be revised to only address updates to the near-term ERA process and Scenarios or methods.

R5. Each Balancing Authority shall provide its near-term ERA process, and Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule.

• BAL-007, R6 duplicates parts of EOP-011, R3 as EOP-011, R3 already requires the RC to review Operating Plan(s).

o BAL-007, Part 6.1 is partially duplicative of EOP-011, Part 3.1.2 as EOP-011, Part 3.1.2 already requires coordination of Operating Plan(s) for Wide area reliability. There is no need to specify “ERA information” as this is already specified in R5.

o BAL-007, Part 6.2 is partially duplicative of EOP-011, Part 3.1.3 as EOP-011, Part 3.1.3 already requires the RC to notify each BA of the results of their review. If R6 is retained, it should be revised as follows:

R6. Within 60 calendar days of receipt of the information identified in Requirement R5, the Reliability Coordinator shall:

6.1. Review each submittal for coordination with other Balancing Authorities’ ERA information in its Reliability Coordinator Area to avoid risks to Wide Area reliability; and

6.2. Notify each Balancing Authority within its Reliability Coordinator Area of the results of its review and specifying any time frame for resubmittal if revisions are needed to address reliability risks.

• If BAL-007, R7 is retained, it should likewise follow the proposed revisions to R6 to align with the approach used in EOP-011, R4 as EOP-011, R4 already requires BAs to resubmit their Operating Plan(s) to the RC within the time period specified by the RC.

R7. Within 60 calendar days of receipt of the Reliability Coordinator's notice under Requirement R6, eEach Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to R6 and resubmit the updated information required in Requirement R4 to its Reliability Coordinator within a time period specified by its Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

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

Likes 0	
Dislikes 0	

Response

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	No
Document Name	

Comment

R2:
The FRCC believes that R2 is too vague, especially the term "Credible". The lack of a specific definition will force individual BAs to create their own standard to be audited against. This situation will have the opposite effect of what is intended. The focus will be on compliance and not on actual Resource Adequacy. Also, the BAs will have to account for compliance risks due to administrative errors, not for inadequate performance that creates a real risk to the BES. The FRCC suggests the drafting team define what the minimal acceptable performance level should be for these assessments and define what "Credible" is intended to address.
R3:
The FRCC acknowledges the intent of the proposed language to minimize forecasted Energy Emergencies, but still has concerns that the proposed language provides no improved clarity regarding this process. The FRCC suggests including language that makes it clear that the BA has sole discretion regarding when it is necessary to notify the RC of forecasted Energy Emergencies. Such discretion would rightly provide due weight to the technical expertise of the BA allowing that functional entity to recognize when there is an imminent risk to the reliability of the BES and when it would be necessary to issue a notification under this Requirement.

R4:
The FRCC is concerned about the requirement for BAs to review and update its near-term ERA process “if needed”. This places an undue burden on BAs to determine when an update is needed. The concern is that if there is no periodic update/review of the document, it has not been evaluated to be “needed”. An auditor could then interpret this as not being maintained properly. There will be an additional compliance burden, where BAs will be forced to explain why updates were not “needed”.
R5:
The FRCC suggests that the ERA process submission to the RC should require resubmission any time a revision is made to the process and on a schedule that is mutually agreed upon between the RC and the BA, not to exceed 24 calendar months if no updates have been made to the current plan. As written, if a BA submits a plan to the RC and then updates the plan document, there is no requirement to send the RC the current version until the next cycle (up to 24 months). There are examples in other NERC Standards that have the entity submit the updated processes within a certain time period after an update, or on schedules that are mutually agreed to with the RC and the entity.

R6:
The FRCC agrees with and supports the Edison Electric Institute (EEI) severity risk comments on R6: Requirement R6 Concerns: EEI notes that Requirement R6 cites certain RC actions related to Requirement R5. Requirement R5 is an administrative Requirement that simply obligates the BA to supply their near-term ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. While Requirement R6 obligates the RC to review the R5 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days this is administrative and therefore should not have a VRF higher than Low. We note the following from the VRF Justification document:
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.
R7:
The FRCC has no comments on R7.
R8:
The FRCC has no comments on R8.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	2022-03_Unofficial Comment Form_BAL-007 and BAL-008_MRO NSRF_06-11-24rev.docx

Comment

Expand Part 2.2. to include “energy transfers between neighboring BAs.” This will align Part 2.2 with Part 1.3.2 as illustrated below. For more details, see our response to Question 1. as illustrated below:

2.2. Known Resource capabilities and operations, including the following:

2.2.1. The effects of a credible energy supply contingency;

2.2.2. The effects of a credible fuel supply contingency;

2.2.3. Unplanned generator outages; and

2.2.4. Energy transfers between neighboring Balancing Authorities

Part 2.3. Eliminate the use of “the best.” This will be difficult to prove in an audit.

2.3. Other Scenarios with a credible or historical risk of occurring based on information available at the time of Scenario creation.

Eliminate or modify BAL-007 requirements R3-R7 to remove duplication with EOP-011 requirements R2-R4. Since the goal of BAL-007 is to perform ERAs and provide the BA with more lead-time to address forecasted Energy Emergency Alerts (as defined in EOP-011, Attachment 1, Section B), **many BAs will likely modify and/or expand existing Operating Plan(s) to comply with BAL-007 and EOP-011 versus drafting new documents.**

Consideration should also be given to aligning and standardizing proposed BAL-007 requirements R3-R7 with EOP-011 requirements R2-R4. Currently, they vary just enough to increase the potential for human error without adding value to the process. For example:

· BAL-007, R5 mandates a 24-month review period for Operating Plan(s) whereas EOP-011, R2 leaves it up to the BA’s discretion.

· BAL-007, R6 mandates a 60-day RC review period whereas EOP-011, R3 requires a 30-day RC review period.

· BAL-007, R7 mandates a 60-day period during which the BA must address issues identified by the RC whereas EOP-011, R4 allows the RC to specify the time period.

Aligning and standardizing BAL-007 with EOP-011 will:

· Enable a smooth transition from BAL-007 to TOP-002 to TOP-001 and EOP-011

· Decrease the potential for human error and eliminate the possibility of double jeopardy

The MRO NSRF proposes the following modifications:

· BAL-007, R3 is duplicative of EOP-011, R2, Parts 2.2 and 2.2.1 as EOP-011 requires “one or more …Operating Plan(s) to mitigate ... Energy Emergencies” and “notification to the RC.” To capture the balance of the intent, the MRO NSRF Recommends a modification to EOP-011, Part 2.2.1. and eliminating R3 from BAL-007:

EOP-011, 2.2.1. Notification to its Reliability Coordinator of:

§ The forecasted Energy Emergency and Operating Plan(s)

§ to include cCurrent and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

BAL-007: (please review the attached document).

· **BAL-007, R4** duplicates parts of EOP-011, R2 as EOP-011, R2 already requires Operating Plan(s) to be maintained. Therefore, retain only that portion of BAL-007, R4 that is new, i.e. to update the near-term ERA process and Scenarios or methods only.

R4. The Balancing Authority shall review and update, if necessary, its near-term ERA process and Scenarios or methods, documented under Requirements R1 through R3 at least once every 24 calendar months.

· **BAL-007, R5** duplicates parts of EOP-011, R2 as EOP-011, R2 already requires Operating Plan(s) to be maintained. Therefore, retain only that portion of BAL-007, R5 that is new, i.e. to update the near-term ERA process and Scenarios or methods only.

R5. Each Balancing Authority shall provide its near-term ERA process, Scenarios or methods, documented under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule.

· **BAL-007, R6** duplicates parts of EOP-011, R3 as EOP-011, R3 already requires the RC to review Operating Plan(s).

o **BAL-007, Part 6.1** is partially duplicative of EOP-011, Part 3.1.2 as EOP-011, Part 3.1.2 already requires coordination of Operating Plan(s) for Wide area reliability. There is no need to specify “ERA information” as this is already specified in R5.

o **BAL-007, Part 6.2** is partially duplicative of EOP-011, Part 3.1.3 as EOP-011, Part 3.1.3 already requires the RC to notify each BA of the results of their review. Recommend the time frame for resubmittal align with EOP-011., Part 3.1.3.

R6. Within 60 calendar days of receipt of the information identified in Requirement R5, the Reliability Coordinator shall:

6.1. Review each submittal for coordination with other Balancing Authorities’ in its Reliability Coordinator Area to avoid risks to Wide Area reliability; and

6.2. Notify each Balancing Authority of the results of its review and specifying any time frame for resubmittal if revisions are needed to address reliability risks.

· **BAL-007, R7** should mirror EOP-011, R4 as EOP-011, R4 already requires BAs to resubmit their Operating Plan(s) to the RC within the time period specified by the RC.

R7. Requirement R6, Each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to R6 and resubmit the updated information required in Requirement R4 to its Reliability Coordinator within a time period specified by its Reliability Coordinator.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC

Answer	No
Document Name	

Comment	
SMUD and BANC agree with the comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
While SRP appreciates the flexibility of creating an operating plan with timelines and scenarios that are appropriate for its BA, more guidance could be helpful to ensure an Operating Plan and associated evidence meets the expectations of the standard.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	

See comments submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO

Answer	No
Document Name	

Comment

NIPSCO supports MISO's feedback.

Likes 0	
Dislikes 0	

Response

Chance Back - Muscatine Power and Water - 1,3,5,6

Answer	No
Document Name	

Comment

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

George E Brown - Pattern Operators LP - 5

Answer	No
Document Name	

Comment

Pattern Energy supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments on this question.

Likes 0	
Dislikes 0	

Response

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 5,6

Answer	Yes
Document Name	

Comment

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	Yes
Document Name	

Comment

Yes, with minor suggested edits

Suggest removing “by a sufficient amount” in R2. It is unnecessary and is vague which may or not be an auditable aspect of the requirement.

Suggest revising R2.1 to Forecasted demand profiles.

Suggest removing “the best” from R2.3. This is subjective and may not be an auditable aspect of the requirement.

EOP-011 does **not** address energy on an hourly basis as this proposed BAL-007 does. Additionally, Energy Emergency does not seem to cover a time horizon in EOP-011 as it is covered by BAL-007.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
The terms 'credible situation', 'credible energy supply Contingency,' and 'credible fuel supply Contingency' are new to this Standard. Consider including clarifications of the meanings of these terms in the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
SPP requests the removal of the "on mutually agreed upon schedule" from R5 leaving a set time requirement of at least once every 24 calendar months. Requiring a mutually agreed upon schedule for each entity is administratively burdensome for the documented evidence.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	

An entity's interpretation of "Sufficient amount" is subject to regulatory review.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
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	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO answers "No." (We had difficulty entering our comments into the SBS.) MISO supports the comments of the MRO NSRF..	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	

Answer	
Document Name	
Comment	

R2 appears to allow the BA to account for EITHER "Forecasted or assumed Demand profiles" OR the disruptions to supply listed under 2.2. Given that most if not all recent reliability events have been caused by a combination of a spike in demand coincident with a failure of generation supply, R2 should require the BA to model a scenario in which both demand is high and generation supply experiences outages.

The modeling of generation supply outages should be based on the most severe historical supply disruptions the BA has experienced, which for most BAs is a correlated loss of gas generation.

Likes 0	
Dislikes 0	
Response	

4. BAL-007-1 Near-term ERAs: The SDT proposes entities use forecasted Demand profiles for the time interval under study for the BAL-007 assessment. The SDT's goal is to align measures for ERAs with those used for EOP-011. Actions taken as part of a BAL-007 Operating Plan should be targeted to minimize any Energy Emergency events. Do you agree with the updated proposed language in Requirement R8? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

George E Brown - Pattern Operators LP - 5

Answer	No
Document Name	
Comment	

Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.

Likes 0	
Dislikes 0	
Response	

Chance Back - Muscatine Power and Water - 1,3,5,6

Answer	No
Document Name	
Comment	

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	
Response	

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO

Answer	No
Document Name	
Comment	

NIPSCO supports MISO's feedback.

Likes 0	
Dislikes 0	

Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	No
Document Name	
Comment	
The language in Requirement R8 should be revised to reflect the fact that conditions may not warrant analysis of each Scenario every time. For example, some Scenarios may be winter only and others summer only. Consequently, the SRC proposes the modifications below: R8. Each Balancing Authority shall perform near-term ERAs according to the process documented in Requirement R1 using at least one of the applicable Scenario(s) or method(s) documented in Requirement R2.	
Likes 0	
Dislikes 0	

Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
As conditions may not warrant analysis of each Scenario every time, the language in R8 should reflect this. For example, some Scenarios may be Winter only and others Summer only. NV Energy proposes the modifications below: **R8.** Each Balancing Authority shall perform near-term ERAs according to the process documented in Requirement R1 using at least one of the applicable Scenario(s) or method(s) documented in Requirement R2.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	No
Document Name	
Comment	
As mentioned in question 3, R8 is unnecessary if we add “implement” in the first requirement.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power endorses the comments provided by the Western Power Pool.	
Likes 0	

Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

Conditions may not warrant analysis of each Scenario every time. Suggested language modification:

R8. Each Balancing Authority shall perform near-term ERAs according to the process documented in Requirement R1 using at least one of the applicable Scenario(s) or method(s) documented in Requirement R2.

Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	

Manitoba Hydro supports comments of MRO NSRF.

Likes 0	

Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren supports MISO's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
If the intent is to utilize the same forecasted Demand profiles that align with EOP-011, then this should be explicit. Specifying EEAs from EOP-011 in R9 does not address the fact that these are different time frames being evaluated. There is no guarantee that the same forecasted Demand profiles will be used or relevant. The Drafting team needs to consider how a compliance auditor will address their intent to use the same data. Each Standard must stand on its own, the auditor will not be able to find fault with the entity if it doesn't use the same data if it is not specified. The Drafting Team should also evaluate how not to use references to other standards, since those standards can change, and it could unintentionally impact this proposed standard. As R8 is currently written, this requirement should be moved from the bottom of the requirement list and combined with R2 or R3 as a performance requirement following the R1 requirement. Alternatively, R8 could be moved up to R3, and renumbering the current requirements R3 through R7.	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	

CHPD supports WPP’s response.

Likes 0	
Dislikes 0	

Response

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA’s full response in question 9.	
Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
The scenarios in R2 only require single contingencies for energy and fuel supply which would “stress” the system. This language is vague and would allow even small contingencies to qualify in many cases. This would be difficult to enforce and leaves the auditor and entity to debate the level of severity required to stress the system. The same is true of the load forecast: the entity could argue that any increase in the load forecast above the base case puts additional stress on the system even if it's small.	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	No
Document Name	
Comment	

The Requirement R9 (revised BAL-007-1 Draft 1 R8) now references the EOP-011 Attachment 1 Section B. EOP-011 Attachment 1 Section B also includes specific responsibilities in addition to the EEA Levels definitions. BC Hydro suggests that EEA Level Definitions are more appropriate in the NERC Glossary of Terms, and recommends against embedding requirements by reference to different Reliability Standards.

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy

Answer	No
Document Name	

Comment

DTE supports MISO's feedback

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

As conditions may not warrant analysis of each Scenario every time, the language in R8 should reflect this. For example, some Scenarios may be Winter only and others Summer only. The MRO NSRF proposes the modifications below:

R8. Each Balancing Authority shall perform near-term ERAs according to the process documented in Requirement R1 using at least one of the applicable Scenario(s) or method(s) documented in Requirement R2.

Likes 0	
Dislikes 0	

Response

Reed Adam - Seattle City Light - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment	
If the intent is to utilize the same forecasted Demand profiles that align with EOP-011, then this should be explicit. Specifying EEAs from EOP-011 in R9 does not address the fact that these are different time frames being evaluated. There is no guarantee that the same forecasted Demand profiles will be used or relevant. The Drafting team needs to consider how a compliance auditor will address their intent to use the same data. Each Standard must stand on its own, the auditor will not be able to find fault with the entity if it doesn't use the same data if it is not specified. The Drafting Team should also evaluate how not to use references to other standards, since those standards can change, and it could unintentionally impact this proposed standard. As R8 is currently written, this requirement should be moved from the bottom of the requirement list and combined with R2 or R3 as a performance requirement following the R1 requirement. Alternatively, R8 could be moved up to R3, and renumbering the current requirements R3 through R7.	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
SCL is in support and alignmnet with WPP's & Idaho's submitted comments.	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
I agree with the comments provided by Western Power Pool.	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No

Document Name	
Comment	
Seattle City Light agrees with WPP Submitted Comment.	
Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Idaho Power agrees with WPP's response to this question, shown below. If the intent is to utilize the same forecasted Demand profiles that align with EOP-011, then this should be explicit. Specifying EEAs from EOP-011 in R9 does not address the fact that these are different time frames being evaluated. There is no guarantee that the same forecasted Demand profiles will be used or relevant. The Drafting team needs to consider how a compliance auditor will address their intent to use the same data. Each Standard must stand on its own, the auditor will not be able to find fault with the entity if it doesn't use the same data if it is not specified. The Drafting Team should also evaluate how not to use references to other standards, since those standards can change, and it could unintentionally impact this proposed standard. As R8 is currently written, this requirement should be moved from the bottom of the requirement list and combined with R2 or R3 as a performance requirement following the R1 requirement. Alternatively, R8 could be moved up to R3, and renumbering the current requirements R3 through R7.	
Likes 0	
Dislikes 0	
Response	

Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	Yes
Document Name	
Comment	
The FRCC suggests that the forecasted Demand profiles align with EOP-011, this should be clearly stated. The FRCC also would like to note that referencing other standards could cause conflict when these standards change and are not aligned with each other.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	

Answer	Yes
Document Name	
Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Seminole agrees with FRCC's comments below The FRCC suggests that the forecasted Demand profiles align with EOP-011, this should be clearly stated. The FRCC also would like to note that referencing other standards could cause conflict when these standards change and are not aligned with each other.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
We assume that this question is referring to BAL-007 Requirement R9, rather than R8 as stated in the question.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	

Answer	Yes
Document Name	
Comment	
EEI supports the proposed changes and linkage to the EOP-011 EEA Measures as contained in Attachment 1 of the Standard.	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
Agree with language in Requirement 8 but this question does not recognize the "assumed Demand profiles" that is allowed by the Requirement language. This question appears to relate to Requirement 3 language(?). Measure M8 needs to add an "s" to "near-term ERA" so that the expectation is not simply one near-term ERA. In some respects, understanding the frequency of the ERAs will dictate how many ERAs would be reviewed to ensure meeting R8's expectations. To support alignment with EOP-011, consider using terms already established in EOP-011 (like "fuel supply").	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	

Comment	
Southern Company agrees that the BAL-007 ERAs, which the SDT propose to be used to predict Forecasted Energy Emergencies or FEEAs, should align with EOP-011 EEA Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI. EEI supports the proposed changes and linkage to the EOP-011 EEA Measures as contained in Attachment 1 of the Standard.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	

WEC Energy Group supports the comments submitted by EEI.

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	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 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	
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	
Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
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	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
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

Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Wayne Guttormson - SaskPower - 1

Answer	
Document Name	

Comment

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO answers "No." (We had difficulty entering our comments into the SBS.) The language in Requirement R8 should be revised to reflect the fact that conditions may not warrant analysis of each Scenario every time. For example, some Scenarios may be winter only and others summer only. Consequently, MISO proposes the modifications below: **R8.** Each Balancing Authority shall perform near-term ERAs according to the process documented in Requirement R1 using ***at least one of*** the ***applicable*** Scenario(s) or method(s) documented in Requirement R2.	
Likes 0	
Dislikes 0	
Response	

5. BAL-007-1 Near-term ERAs: The SDT updated Requirement R9 based on industry feedback. Do you agree with the updated proposed language in Requirement R9? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Idaho Power agrees with WPP's response to this question, shown below. R9 does a good job of establishing a performance target, unlike many of the other requirements of TOP-007. R9 should follow good standards writing style where the responsible entity is the first part of the sentence, and the performance actions follow. The Drafting Team should consider rewriting the first sentence as: "The Balancing Authority shall implement Operating Plan(s), as documented in Requirement R3, when near-term ERAs identifies any of the following forecasted Energy Emergencies:"	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seattle City Light agrees with WPP Submitted Comment.	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
I agree with the comments provided by Western Power Pool.	

Likes 0	
Dislikes 0	

Response

Michael Jang - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

SCL is in support and alignmnet with WPP's & Idaho's submitted comments.

Likes 0	
Dislikes 0	

Response

Reed Adam - Seattle City Light - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

R9 does a good job of establishing a performance target, unlike many of the other requirements of TOP-007. R9 should follow good standards writing style where the responsible entity is the first part of the sentence, and the performance actions follow. The Drafting Team should consider rewriting the first sentence as: “The Balancing Authority shall implement Operating Plan(s), as documented in Requirement R3, when near-term ERAs identifies any of the following forecasted Energy Emergencies:”

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy

Answer	No
Document Name	

Comment

DTE supports MISO's feedback

Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	No
Document Name	
Comment	
The Requirement R9 references the EOP-011 Attachment 1 Section B. EOP-011 Attachment 1 Section B also includes specific responsibilities in addition to the EEA Levels definitions. BC Hydro suggests that EEA Level Definitions are more appropriate in the NERC Glossary of Terms, and recommends against embedding requirements by reference to different Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments but also has concerns that EEA 1s should not be included within this requirement. Energy assurance should focus on EEA 2s and 3s which pose elevated risk to reliability.	

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 recommended changes for BAL-007-1 R9.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA's full response in question 9.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	

Response	
Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	

Black Hills Corporation is in agreement with EEI comments here: Requirement R10 lacks sufficient clarity to ensure that RC will not be needlessly burdened to report forecasted Energy Emergencies that do not pose imminent risk to BES reliability. To address our concern, we offer edits in boldface that provide greater clarity when the RC needs to meet the notification requirements identified in Requirement R10.

In addition to EEI comments, Black Hills feels 10.2 can be removed from the Requirement. We believe 10.3 is sufficient enough to cover the need. The RC has the ability to utilize several means to deem credible a forecasted Energy emergency.

R10 Each Reliability Coordinator, within 24 hours of receiving a notification **pursuant to Requirement R3** that **1) has been transmitted from** a Balancing Authority within its footprint**, 2) meets the criteria set in 10.1 through 10.3, and 3)** has **forecast an Energy Emergency and** implemented an Operating Plan pursuant to Requirement R8; shall notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators of the forecasted condition(s), and the Balancing Authority's Operating Plan(s). [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

10.1 Forecasted a reliability concern which has the potential of occurring within the 2 days or within the upcoming week; and

10.2 Is based on reliable weather data; and

10.3 Has been deemed credible by the RC.

Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	

LG&E & KU agree with comments provided by EEI.

Likes 0	
Dislikes 0	
Response	

Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
CHPD supports WPP’s response.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company supports the EEI comments and agrees with the EEI language changes.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
TEPC agrees with EEI's comments - Requirement R10 lacks sufficient clarity to ensure that RC will not be needlessly burdened to report forecasted Energy Emergencies that do not pose imminent risk to BES reliability.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	

Answer	No
Document Name	
Comment	

R9 does a good job of establishing a performance target, unlike many of the other requirements of TOP-007. R9 should follow good standards writing style where the responsible entity is the first part of the sentence, and the performance actions follow. The Drafting Team should consider rewriting the first sentence as: “The Balancing Authority shall implement Operating Plan(s), as documented in Requirement R3, when near-term ERAs identify any of the following forecasted Energy Emergencies:”

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

Ameren supports MISO's comments on this project.

Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1,3,5,6

Answer	No
Document Name	
Comment	

Manitoba Hydro supports comments of MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	
Comment	

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1,6

Answer	No
Document Name	
Comment	

The R9 requirement should not require the BA to "implement" an Operating Plan(s) upon a "forecasted" Energy Emergency. Suggested language modifications:

R9. If a near-term ERA identifies any of the following forecasted Energy Emergencies listed below, the Balancing Authority shall continue to monitor and implement an Operating Plan(s), as documented in Requirement R3, when appropriate.

Likes 0	
Dislikes 0	
Response	

Hayden Maples - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5

Likes 0	
Dislikes 0	
Response	

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power endorses the comments provided by the Western Power Pool.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1,3

Answer	No
Document Name	

Comment

Exelon supports the concerns stated in the EEI comments.

Likes 0	
Dislikes 0	

Response

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

Supporting EEI comments.

Likes 0	
Dislikes 0	

Response

Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	No

Document Name	
Comment	

EEAs should be left for BAs to enter as currently defined. Issuing an EEA too far out will not carry much weight because circumstances will likely change the closer to next day a BA approaches.

Flooding an RC with notifications regarding implementation of an Operating Plan days ahead of time is too much. The RC role by definition is to prevent or mitigate operating situations in both next-day analysis and real-time operations. This is the time frame that an RC should focus on and not days ahead of next-day operations. Too many notifications to an RC takes their focus away from real-time operations.

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	
Comment	

Requirement R10 lacks sufficient clarity to ensure that RC will not be needlessly burdened to report forecasted Energy Emergencies that do not pose imminent risk to BES reliability. To address our concern, we offer edits in boldface that provide greater clarity when the RC needs to meet the notification requirements identified in Requirement R10.

R10 Each Reliability Coordinator, **who receives notification of a forecasted Energy Emergency, pursuant to Requirement R3 that includes an implemented Operating Plan pursuant to Requirement R8 that is forecasted to be a reliability concern within the upcoming week and evaluated as credible by the Reliability Coordinator;** shall within 24 hours of receiving **the** notification, notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators of the forecasted condition(s), and the Balancing Authority's Operating Plan(s). [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	
Comment	

As written, requirement R9 requires the BA to "implement" an Operating Plan(s) upon identifying a forecasted Energy Emergency. This may result in wasted effort when a forecast fails to result in a Real-Time Emergency. Therefore, some consideration should be given to monitoring the situation and

acting when warranted so that a higher bar (more effort) isn't required in managing issues identified in a near-term ERA than those identified in an Operational Planning Analysis (TOP-002) or Real-Time Assessment (TOP-001). NV Energy proposes the modifications below: **R9.** If a near-term ERA identifies any of the following forecasted Energy Emergencies listed below, the Balancing Authority shall continue to monitor and implement an Operating Plan(s), as documented in Requirement R3, when appropriate.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
USV is concerned with the potential for duplicative efforts between EOP-011 R2 and BAL-007 R9; both require the BA to implement operating plans for forecasted energy emergencies. USV supports the additional context provided by MISO in their comments to this question.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
APS is of the opinion that R9 should be removed from BAL-007-1 as it reaches beyond the near-term scope of BAL-007-1 and falls within Real-time Operations, specifically EOP-011. The SDT should consider revising BAL-007-1 R3 to include implementing the Operating Plan should conditions arise. If the intent of near-term ERAs is to have time to implement mitigation actions with longer lead times to minimize energy emergencies and overall risk, then the near-term ERA Operating Plan would address and/or reduce the identified risks. Should Risk occur closer to Real-time, EOP-011 R2 would be implemented.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	

Answer	No
Document Name	

Comment
(footnote: SPP is a party to these comments however does not support the references about duplication with EOP-011 requirements. SPP supports the need for reporting ERA results in BAL-007 however there is lack of clarity between the BAL-007 and EOP-011 obligations.) As written, requirement R9 requires the BA to “implement” an Operating Plan(s) upon identifying a forecasted Energy Emergency. This is duplicative of EOP-011 Requirement R2, which already addresses implementation of Operating Plans in multiple time horizons to mitigate Energy Emergencies. In addition to being duplicative, BAL-007 Requirement R9 may result in wasted effort when a forecast fails to result in a Real-Time Emergency. Therefore, Requirement R9 should be removed to avoid duplication of EOP-011. If R9 is retained, it should be revised to consider the wisdom of monitoring the situation and acting when warranted so that a higher bar (more effort) isn’t required in managing issues identified in a near-term ERA than those identified in an Operational Planning Analysis (TOP-002) or Real-Time Assessment (TOP-001). If R9 is retained, the SRC proposes the modifications below: R9. If a near-term ERA identifies any of the following forecasted Energy Emergencies listed below, the Balancing Authority shall continue to monitor the situation and implement an Operating Plan(s), as documented in Requirement R3, when appropriate.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	2022-03_Unofficial Comment Form_BAL-007 and BAL-008_MRO NSRF_06-11-24rev.docx

Comment
As written, requirement R9 requires the BA to “implement” an Operating Plan(s) upon identifying a forecasted Energy Emergency. This may result in wasted effort when a forecast fails to result in a Real-Time Emergency. Therefore, some consideration should be given to monitoring the situation and

acting when warranted so that a higher bar (more effort) isn't required in managing issues identified in a near-term ERA than those identified in an Operational Planning Analysis (TOP-002) or Real-Time Assessment (TOP-001). The MRO NSRF proposes the modifications below:

R9. If a near-term ERA identifies any of the following forecasted Energy Emergencies listed below, the Balancing Authority shall continue to monitor and implement an Operating Plan(s), as documented in Requirement R3, when appropriate.

Likes 0	
Dislikes 0	

Response

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4

Answer	No
Document Name	

Comment

Madison Gas and Electric supports the comments of the MRO NSRF.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Assuming the scenarios apply in more than one real-world situation that we might encounter, a high-level plan may be implemented. Specific actions should not be included in operating plans such that they are not useful in reality.

Likes 0	
Dislikes 0	

Response

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6

Answer	No
Document Name	

Comment

See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	
Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments on this question.	

Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
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	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	Yes
Document Name	
Comment	

This language seems to duplicate EOP-011.

Likes 0	
Dislikes 0	
Response	

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	Yes
Document Name	
Comment	

ISO-NE agrees with the addition of the Forecasted EEA aspects of BAL-007.

For example this allows entities to perform additional assessments and notification activities without implementing the EEA actions as determined by EOP-011.

A specific example is as follows:

For an Energy Alert-

An Energy Alert exists when either an FEEA1 or FEEA2 take place in days 6 through 42 of the ERA.

1) During an Energy Alert, to the extent possible, the reasoning for the alert should be included in the results.

2) Generator Fuel and Emissions Surveys shall be distributed on a daily basis.

3) Additional ERAs shall be performed based on available data, which includes information obtained through the Fuel Emission Survey.

4) Results of the updated ERA shall be published daily on the entity's external website.

In this case no actions are taken other than increasing frequency of the ERAs, and notifications via publishing on the entity's website.

Likes 0	
Dislikes 0	
Response	

Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Puget Sound Energy agrees with WPP's response to this question, shown below.	
Likes 0	
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Seminole agrees with FRCC's comments below The FRCC agrees with and supports the Edison Electric Institute (EEI) comments on question #5: Requirement R10 lacks sufficient clarity to ensure that RC will not be needlessly burdened to report forecasted Energy Emergencies that do not pose imminent risk to BES reliability. To address our concern, we offer edits in boldface that provide greater clarity when the RC needs to meet the notification requirements identified in Requirement R10.	
Likes 0	
Dislikes 0	
Response	

LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	Yes
Document Name	
Comment	
The FRCC agrees with and supports the Edison Electric Institute (EEI) comments on question #5: Requirement R10 lacks sufficient clarity to ensure that RC will not be needlessly burdened to report forecasted Energy Emergencies that do not pose imminent risk to BES reliability. To address our concern, we offer edits in boldface that provide greater clarity when the RC needs to meet the notification requirements identified in Requirement R10. R10 Each Reliability Coordinator, who receives notification of a forecasted Energy Emergency, pursuant to Requirement R3 that includes an implemented Operating Plan pursuant to Requirement R8 that is forecasted to be a reliability concern within the upcoming week and evaluated as credible by the Reliability Coordinator; shall within 24 hours of receiving the notification ,notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators of the forecasted condition(s), and the Balancing Authority's Operating Plan(s). [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
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	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO answers "No." (We had difficulty entering our comments into the SBS.)

As written, requirement R9 requires the BA to “implement” an Operating Plan(s) upon identifying a forecasted Energy Emergency. This is duplicative of EOP-011 Requirement R2, which already addresses implementation of Operating Plans in multiple time horizons to mitigate Energy Emergencies. In addition to being duplicative, BAL-007 Requirement R9 may result in wasted effort when a forecast fails to result in a Real-Time Emergency. Therefore, Requirement R9 should be removed to avoid duplication of EOP-011. If R9 is retained, it should be revised to consider the wisdom of monitoring the situation and acting when warranted so that a higher bar (more effort) isn’t required in managing issues identified in a near-term ERA than those identified in an Operational Planning Analysis (TOP-002) or Real-Time Assessment (TOP-001). If R9 is retained, MISO proposes the modifications below:

R9. If a near-term ERA identifies any of the following forecasted Energy Emergencies listed below, the Balancing Authority shall continue to monitor the situation and implement an Operating Plan(s), as documented in Requirement R3, when appropriate.

Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	
Response	

6. BAL-007-1 Near-term ERAs: The SDT updated the implementation plan to allow for 18 months for Requirements R1 through R3 and 24 months for Requirements R4 through Requirement R10 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	No
Document Name	
Comment	
The FRCC does not support an 18-month implementation period for Requirements R1 through R3. The resulting burden of work associated with changing internal processes, developing credible scenarios and operating plans will be very time consuming. The FRCC recommends an implementation period of **at least** 24 months for all requirements.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	No
Document Name	
Comment	
The SRC notes that entities are developing improvements to internal processes to improve energy capabilities for the operations planning horizon while these new NERC requirements are yet to be finalized. It is unknown at this time what the impacts of the new requirements will be on the ISO/RTOs but there will be resources needed to fully integrate and implement the NERC standards with the internal processes. Consequently, while the SRC appreciates the updates to the implementation plan, the SRC requests that the implementation plan be further revised to allow 36 months for the implementation of all Requirements.	

Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
APS agrees with the following EEI comments: EEI does not support 18 months for Requirements R1 through R3. The work associated with changing internal processes, developing credible scenarios and operating plans will be time consuming. To address this concern, the implementation plan should allow for 24 months for all of the Requirements.	
Likes 0	
Dislikes 0	
Response	
LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seminole agrees with FRCC's comments below	

The FRCC does not support an 18-month implementation period for Requirements R1 through R3. The resulting burden of work associated with changing internal processes, developing credible scenarios and operating plans will be very time consuming. The FRCC recommends an implementation period of at least 24 months for all requirements.	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
USV supports the comments provided by MISO regarding the number of resources required to address BAL-007 implementation.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support 18 months for Requirements R1 through R3. The work associated with changing internal processes, developing credible scenarios and operating plans will be time consuming. To address this concern, the implementation plan should allow for 24 months for all of the Requirements.	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	

Supporting EEI comments.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power endorses the comments provided by the Western Power Pool.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 6	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
Clarity is needed in the Implementation Plan as it states that BAL-007-1 will be “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.” Then, for phased-in Compliance Date there is language for R1, R2, and R3 that states entities have 18 months after the effective date of the Standard in essence allowing 36 months after the effective date for	

entities to be compliant. Other Requirements also have the “following the effective date” with 24 month additional time period. Please draw a timeline of expected implementation so that all parties, including FERC, are in clear understanding of when Requirements actually become auditable and enforceable. As is, the first 18 months, as written, is not an effective time period as nothing changes in terms of efforts. Drawing a timeline associated with effective implementation dates should be part of the Standards process.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

The Timeline proposed states that the entities have 18 months to comply with R1 through R3. The problem is that under R1 the ERA process must be sent to the RC for review. If the RC is sent the ERA process for review at the end of the 18-month period, the RC then has 60 days to review, and can send the process back to the entity for correction. The entity can take another 60 days to correct and resubmit the process to the RC. Finally, the RC has an additional 60 days to review and accept the modified process. Once the plan is accepted by the RC, the entity can begin to meet R2 and R3 compliance. Stepping through this process results in significant delay in implementation of R2 and R3. If the process is followed as the implementation plan suggests, entities run the risk of creating the ERA process, developing Scenarios and operating plans, that will all have to be redone due to a problem that the RC finds with their ERA process.

The Drafting Team should consider adjusting the implementation of BAL-007. Perhaps it is more appropriate to require implementation of R1 by 12 months after the effective date of the standard, R4 through R7 can be implemented by 18 months after the effective date, and full implementation of the standards will be completed by 24 months after the effective date.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment

TEPC agrees with EEI's comments - EEI does not support 18 months for Requirements R1 through R3. The work associated with changing internal processes, developing credible scenarios and operating plans will be time consuming. To address this concern, the implementation plan should allow for 24 months for all of the requirements.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Southern Company supports the EEI comments and agrees that 24 months is a more reasonable implementation timeframe for all requirements.

Likes 0	
Dislikes 0	

Response

Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group

Answer	No
Document Name	

Comment

CHPD supports WPP’s response.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

LG&E & KU agree with comments provided by EEI.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with the longer timeline (24 months) proposed by EEI. EEI does not support 18 months for Requirements R1 through R3. The work associated with changing internal processes, developing credible scenarios and operating plans will be time consuming. To address this concern, the implementation plan should allow for 24 months for all of the Requirements.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA's full response in question 9.	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	No
Document Name	
Comment	
PNM support a 24-month implementation timeline for all BAL-007-1 requirements.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	

Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy supports proposed EEI language modifications for Question 6.	
Likes 0	
Dislikes 0	
Response	
Reed Adam - Seattle City Light - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment	
The Timeline proposed states that the entities have 18 months to comply to R1 through R3. The problem is that under R1 the ERA process must be sent to the RC for review. If the RC is sent the ERA process for review at the end of the 18-month period, the RC then has 60 days to review, and can send the process back to the entity for correction. The entity can take another 60 days to correct and resubmit the process to the RC. Finally, the RC has an additional 60 days to review and accept the modified process. Once the plan is accepted by the RC, the entity can begin to meet R2 and R3 compliance. Stepping through this process results in significant delay in implementation of R2 and R3. If the process is followed as the implementation plan suggests, entities run the risk of creating the ERA process, developing Scenarios and operating plans, that will all have to be redone due to a problem that the RC finds with their ERA process. The Drafting Team should consider adjusting the implementation of BAL-007. Perhaps it is more appropriate to require implementation of R1 by 12 months after the effective date of the standard, R4 through R7 can be implemented by 18 months after the effective date, and full implementation of the standards will be completed by 24 months after the effective date.	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
SCL is in support and alignmnet with WPP's & Idaho's submitted comments.	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
I agree with the comments provided by Western Power Pool.	
Likes 0	
Dislikes 0	
Response	

Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seattle City Light agrees with WPP Submitted Comment.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Idaho Power agrees with WPP's response to this question, shown below. The Timeline proposed states that the entities have 18 months to comply to R1 through R3. The problem is that under R1 the ERA process must be sent to the RC for review. If the RC is sent the ERA process for review at the end of the 18-month period, the RC then has 60 days to review, and can send the process back to the entity for correction. The entity can take another 60 days to correct and resubmit the process to the RC. Finally, the RC has an additional 60 days to review and accept the modified process. Once the plan is accepted by the RC, the entity can begin to meet R2 and R3 compliance. Stepping through this process results in significant delay in implementation of R2 and R3. If the process is followed as the implementation plan suggests, entities run the risk of creating the ERA process, developing Scenarios and operating plans, that will all have to be redone due to a problem that the RC finds with their ERA process. The Drafting Team should consider adjusting the implementation of BAL-007. Perhaps it is more appropriate to require implementation of R1 by 12 months after the effective date of the standard, R4 through R7 can be implemented by 18 months after the effective date, and full implementation of the standards will be completed by 24 months after the effective date.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
While ISO-NE agrees that the timeline for the Implementation Plan is specific. R4 could also be effective 18 months after the approval of the Standard. The reasoning is that R4 requires a review and update of the ERA Process within 24 months. If the original ERA Document is approved by 18 months, R4 and its reviews should be effective the same time as the original ERA process document. ISO-NE would also support an extended Implementation Plan to 36 months for all requirements.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	

Ameren supports MISO's comments on this project.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 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	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
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	
Ben Hammer - Western Area Power Administration - 1,6	
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	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	

Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO answers "No." (We had difficulty entering our comments into the SBS.) The resources and expertise needed to implement BAL-007 (particularly if ERAs are going to be automated) may already be engaged on other long-term projects that will need to be completed before being available to address BAL-007 implementation. Consequently, while the SRC appreciates the updates to the implementation plan, the SRC requests that the implementation plan be further revised to allow 36 months for the implementation of all Requirements. T	
Likes 0	
Dislikes 0	
Response	

7. BAL-007-1 Near-term ERAs: The SDT believes that fuel data information needed to address BAL-007-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Idaho Power agrees with WPP's response to this question, shown below. The BAs can expand their Operational Reliability Data requests through TOP-003, however this could further slow the implementation of proposed standard BAL-007 due to the time needed to notify the entities, and for them to turn the information around back to the BA before the ERA process can begin. Fuel information from entities not listed in TOP-003 can be problematic. This includes natural gas suppliers, and entities not registered as users, owners or operators of the BES, not under the purview of the BA or who have contracts specifically limiting access to market sensitive information.	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seattle City Light agrees with WPP Submitted Comment.	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

I agree with the comments provided by Western Power Pool.

Likes 0	
Dislikes 0	

Response

Michael Jang - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

SCL is in support and alignmnet with WPP's & Idaho's submitted comments.

Likes 0	
Dislikes 0	

Response

Reed Adam - Seattle City Light - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

The BAs can expand their Operational Reliability Data requests through TOP-003, however this could further slow the implementation of proposed standard BAL-007 due to the time needed to notify the entities, and for them to turn the information around back to the BA before the ERA process can begin.
Fuel information from entities not listed in TOP-003 can be problematic. This includes natural gas suppliers, and entities not registered as users, owners or operators of the BES, not under the purview of the BA or who have contracts specifically limiting access to market sensitive information.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

Past practice clearly indicates a change to TOP-003 is necessary to collect "fuel supply and inventory concerns" information year-round.

· TOP-003-5 is unclear as to what information must be provided by entities in support of ERAs. Requirement R1 is limited to "Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." (Items required in support of TOP-002 and TOP-001 only). When viewed in conjunction with R2, a case could be made that TOP-003, R2 likewise is limited in support of TOP-002 and TOP-001 only.

· In addition, if fuel data needed by BAs to address BAL-007 is covered under TOP-003, why then was TOP-003 updated to specifically require information regarding "fuel supply and inventory concerns" under cold weather conditions pursuant to Project 2019-06 and further expanded under Project 2021-07? (See **TOP-003-5** and **TOP-0003-6.1**, **Part 2.3.1.2**)

Both Cold Weather projects modified TOP-003 to mandate the provision of "fuel supply and inventory concerns," so that it only applies during local forecasted Cold Weather conditions. Therefore, **a change to TOP-003 would be required to mandate the provision of "fuel supply and inventory concerns" year-round.**

Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

MISO answers "No." (We had difficulty entering our comments into the SBS.)

Past experience clearly indicates a change to TOP-003 is necessary to enable BAs to collect the necessary information regarding "fuel supply and inventory concerns" year-round (to the extent this information is even available from NERC-registered entities).

- TOP-003-5 does not extend to information needed to perform ERAs. Requirement R1 is limited to "Operational Planning Analyses, Real-time monitoring, and Real-time Assessments" (items required in support of TOP-002 and TOP-001 only). When viewed in conjunction with R2, a case could be made that TOP-003-5, R2 is likewise limited to information needed for TOP-002 and TOP-001 only.
- In addition, TOP-003 was recently updated to specifically address information regarding "fuel supply and inventory concerns" under cold weather conditions pursuant to Project 2019-06 and further expanded under Project 2021-07 (*See* TOP-003-5 and TOP-0003-6.1, Part 2.3.1.2). This indicates that TOP-003 does not address fuel-related information that would be needed to implement BAL-008.

The modifications to TOP-003 to mandate the provision of "fuel supply and inventory concerns," only require this information to be provided during local forecasted Cold Weather conditions. Therefore, a change to TOP-003 would be required to mandate the provision of "fuel supply and inventory concerns" year-round if BAL-008 persists in its current form.

Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	

Answer	No
Document Name	
Comment	
DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	No
Document Name	
Comment	
TOP-003 covers data needs specific to Operations Planning Assessments (OPA), Real-time Assessments (RTA) and Real-time Monitoring (RTM) and may not provide sufficient authority for the BA to request specific data necessary for ERAs. BC Hydro suggests that a revision to the current TOP-003 or a new ERA-specific Requirement would be necessary.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
This could potentially put the BA at odds with the GO and GOP as to the applicability of TOP-003 in these scenarios. TOP-003 today is only used for data in the near real time horizon and the GO or GOP could argue that the data required for these studies is beyond the scope of TOP-003. While the BAs could attempt to use TOP-003 for this data acquisition, it would be better to include the requirement to supply the data needed in the standard.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	No
Document Name	
Comment	

Please see BPA's full response in question 9.

Likes 0	
Dislikes 0	
Response	

Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group

Answer	No
Document Name	
Comment	

CHPD supports WPP's response.

Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	
Comment	

The BAs can expand their Operational Reliability Data requests through TOP-003, however this could further slow the implementation of proposed standard BAL-007 due to the time needed to notify the entities, and for them to turn the information around back to the BA before the ERA process can begin.

Fuel information from entities not listed in TOP-003 can be problematic. This includes natural gas suppliers, and entities not registered as users, owners or operators of the BES, not under the purview of the BA or who have contracts specifically limiting access to market sensitive information.

Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren supports MISO's comments on this project.	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1,6	
Answer	No

Document Name	
Comment	

Current practice clearly indicates that a change to TOP-003 is necessary to collect “fuel supply and inventory concerns” information year-round.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 7

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power endorses the comments provided by the Western Power Pool.

Likes 0	
Dislikes 0	

Response

Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	No
Document Name	

Comment

It will likely be a problem getting fuel information from entities that are not Registered Entities as they are not required to comply with the NERC Reliability Standards.

Likes 0	
Dislikes 0	

Response

Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6

Answer	No
Document Name	

Comment

PSE generally agrees with WPP's response to this question. In addition, the fuel data necessary is often times non-public information and subject to commercial agreements between the generating plants and their fuel suppliers. Getting the nature of those contracts, including measures for curtailment will create a FERC SOC concern since the utility often has their own units and then balances third party resources within the BA.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

Past practice clearly indicates a change to TOP-003 is necessary to collect "fuel supply and inventory concerns" information year-round.

{C}· TOP-003-5 is unclear as to what information must be provided by entities in support of ERAs. Requirement R1 is limited to "Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." (Items required in support of TOP-002 and TOP-001 only). When viewed in conjunction with R2, a case could be made that TOP-003, R2 likewise is limited in support of TOP-002 and TOP-001 only.

{C}· In addition, if fuel data needed by BAs to address BAL-007 is covered under TOP-003, why then was TOP-003 updated to specifically require information regarding "fuel supply and inventory concerns" under cold weather conditions pursuant to Project 2019-06 and further expanded under Project 2021-07? (*See* **TOP-003-5** and **TOP-0003-6.1, Part 2.3.1.2**)

Both Cold Weather projects modified TOP-003 to mandate the provision of “fuel supply and inventory concerns,” so that it only applies during local forecasted Cold Weather conditions. Therefore, **a change to TOP-003 would be required to mandate the provision of “fuel supply and inventory concerns” year-round.**	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
TOP-003 enables the BA’s to collect the necessary information, but it does not clearly specify the data necessary for ERAs, which are more akin to planning studies. USV supports the additional comments and suggestions provided by MISO.	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Puget Sound Energy (PSE) generally agrees with WPP’s response to this question. Additional PSE comments are shown below. The fuel data necessary is often times non-public information and subject to commercial agreements between the generating plants and their fuel suppliers. Getting the nature of those contracts, including measures for curtailment will create a FERC SOC concern since the utility often has their own units and then balances third party resources within the BA.	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	No
Document Name	

Comment	
TOP-003-5 does not cover the data requirements for ERA and we believe this could lead to issues with enforcing the standard. Two possible options for addressing this are 1) modify TOP-003-5 to include data requirements for ERA or 2) add a requirement to BAL-007-1 to address this data requirement.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	No
Document Name	
Comment	
Past experience clearly indicates a change to TOP-003 is necessary to enable BAs to collect the necessary information regarding “fuel supply and inventory concerns” year-round (to the extent this information is even available from NERC-registered entities). • TOP-003-5 does not extend to information needed to perform ERAs. Requirement R1 is limited to “Operational Planning Analyses, Real-time monitoring, and Real-time Assessments” (items required in support of TOP-002 and TOP-001 only). When viewed in conjunction with R2, a case could be made that TOP-003-5, R2 is likewise limited to information needed for TOP-002 and TOP-001 only. • In addition, TOP-003 was recently updated to specifically address information regarding “fuel supply and inventory concerns” under cold weather conditions pursuant to Project 2019-06 (See TOP-003-5 and TOP-0003-6.1, Part 2.3.1.2). This indicates that TOP-003 does not address fuel-related information that would be needed to implement BAL-007. The modifications to TOP-003 to mandate the provision of “fuel supply and inventory concerns,” only require this information to be provided during local forecasted Cold Weather conditions. Therefore, a change to TOP-003 would be required to mandate the provision of “fuel supply and inventory concerns” year-round if BAL-007 persists in its current form.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	

Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	
Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	

Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments on this question.	
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. - 3,4,5,6, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments submitted by EEI and agrees that TOP-003 provides the mechanism needed by BAs to request fuel data information.	

Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation already has experience with TOP-003 and feels fuel data information can be achieved by adding it to our data specs.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
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	
Likes 0	
Dislikes 0	

Response	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	
WECC agrees with the concept that may already be in place for EOP-011 fuel data information required. However, the DT should consider using the same language as EOP-011. Additionally, TOP-003 may be considered limiting in that it is for data used in Operation Planning Analyses, Real-time monitoring, and Real-time Assessments. DT should provide language in the Technical Rationale to indicate an ERA is a form of OPA that would cover next day operations so that the definition of OPA is met (and alleviate anyone's concerns regarding use of TOP-003).	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	

Under TOP-003 R2 the "Each BA shall maintain a documented specification for the data necessary for it to perform its **analysis function** and real-time monitoring", with an Operations Planning time horizon.

ISO-NE believes that TOP-003 R2 satisfies the data collection requirements of BAL-007 and no additional fuel data collection requirement wholly contained in BAL-007 or a modification of TOP-003 R2 is required.

Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI agrees that TOP-003 provides the mechanism needed by BAs to request fuel data information.

Likes 0	
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	

Seminole agrees with FRCC's comments below

The FRCC agrees that TOP-003 provides the mechanism needed by BAs to request fuel data information.

Likes 0	

Dislikes 0	
Response	
LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	Yes
Document Name	
Comment	
The FRCC agrees that TOP-003 provides the mechanism needed by BAs to request fuel data information.	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion	
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	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
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	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

8. BAL-007-1 Near-term ERAs: The SDT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request 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.

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
SMUD and BANC agree with the comments submitted by Tacoma Power.	
Likes 0	
Dislikes 0	
Response	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	No
Document Name	
Comment	
The FRCC does not have any means to conduct an analysis or study determining that this proposal is cost-effective, and therefore does not support this statement. As previously noted, the proposed standard will most likely lead to an increase in staffing and administrative costs for all BAs and the RC function.	
Likes 0	
Dislikes 0	
Response	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	No
Document Name	
Comment	
(footnote: SPP is a party to these comments however does not support the references about duplication with EOP-011 requirements. SPP supports the need for reporting ERA results in BAL-007 however there is lack of clarity between the BAL-007 and EOP-011 obligations.) As detailed elsewhere in the SRC's comments, BAL-007 is currently substantively duplicative of EOP-011, TOP-002, and IRO-014 while simultaneously imposing additional administrative burdens that do not enhance system reliability. In addition, the standard presumes that BAs have access to fuel-related information that they do not possess and currently have no cost-effective method of obtaining. Addressing the information provision issues and eliminating duplication and overlap with other standards would minimize bureaucracy and allow entities to comply with BAL-007 in a more cost-effective manner. For more details, see the SRC's response to Questions 3, 7, and 9.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
APS is in the opinion that implementation of BAL-007-1 would not meet the SAR in a cost effective manner as it creates an administrative burden for entities to either replace or revise existing processes that work well and may create a need for additional staffing to manage continuous near-term ERAs.	

Likes 0	
Dislikes 0	
Response	
LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seminole agrees with FRCC's comments below The FRCC does not have any means to conduct an analysis or study determining that this proposal is cost-effective, and therefore does not support this statement. As previously noted, the proposed standard will most likely lead to an increase in staffing and administrative costs for all BAs and the RC function.	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Puget Sound Energy (PSE) agrees with WPP's response to this question. Additional PSE comments are shown below.	

In non-organized markets (WECC) the impact of BA to BA interchange scheduled by merchants make implementation difficult to impossible. This could be alleviated by utilizing historic interchange numbers similar to long term planning; however, in real time the interchange numbers have a very large impact on performance. Those final numbers often aren't finalized until an hour prior to the hour. In the day ahead time frame the BA has some indication of possible range; however both those times are outside the scope of the BAL standards. These transactions are market/merchant related and there is no mechanism to have commitments or data within these standards time frame.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

Eliminating duplication and overlap with other standards would minimize bureaucracy and allow entities to comply with BAL-007 in a more cost-effective manner. For more details, see our response to Questions 3 and 7.

Likes 0	
Dislikes 0	

Response

Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6

Answer	No
Document Name	

Comment

PSE agrees with WPP's response to this question. Additionally, in non-organized markets (WECC) the impact of BA to BA interchange scheduled by merchants make implementation difficult to impossible. This could be alleviated by utilizing historic interchange numbers similar to long term planning; however, in real time the interchange numbers have a very large impact on performance. Those final numbers often aren't finalized until an hour prior to the hour. In the day ahead time frame the BA has some indication of possible range; however both those times are outside the scope of the BAL standards. These transactions are market/merchant related and there is no mechanism to have commitments or data within these standards time frame.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC

Answer	No
Document Name	

Comment

R4 : This requirement is redundant with the “maintain” obligation state in R1, R2 and R3.

When there is only one RC and BA in an Interconnexion, R5 to R7 should be not applicable.

Likes 0	
Dislikes 0	

Response

Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	No
Document Name	

Comment

Implementation of this standard will not be cost effective because the additional study work that will be required will likely require additional personnel.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power does not agree that the newly proposed BAL-007-1 is cost effective, because it does not allow or recognize the efficiencies of BAs participating in an energy resource adequacy group, like the Western Power Pool. The current language in the Standard requires an individual BA to perform an ERA. An entity that jointly prepares their ERA with a group or an adjacent BA would not meet strict compliance. Additionally, smaller BAs need to coordinate with other BAs to ensure adequate resources. A single BA may not have sufficient resources to meet the adequacy criteria set in the Standard. Tacoma Power recommends that the Requirements be edited to allow joint preparation of ERAs. For example, “Each Balancing Authority, **whether individually or jointly with a resource adequacy group**, shall perform near-term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.”

Likes 0	
Dislikes 0	

Response	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 8	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
As written, there is duplication/overlap with other standards. Modifications (such as suggested above) are needed to reduce duplication/overlap.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren supports MISO's comments on this project.	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
We are not aware of any analysis or study determining that this proposal is cost-effective, and therefore do not support this statement. Since the proposed standard requires the BA to be responsible to meet the ERA studies, it will most likely require the hiring of specialized skill sets that are not currently on staff. This can have a significant cost impact to BAs when the resource adequacy analyses are shifted from the Resource Planners to the BAs. The cost/benefit has not been articulated by the Drafting Team, and when this question was asked during a Drafting Team workshop, the Drafting Team admitted there was no analysis for cost effectiveness. BAs, if given the opportunity, will try and pool their resources and create Emergency Energy Plans and form Resource Adequacy Pools. The current proposed BAL-007 does not provide the ability to do that and will therefore be a burden on many BAs.	
Likes 0	
Dislikes 0	

Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
TEPC does not agree, The new requirements will require additional staff and change in office configuration to add new desks.	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
CHPD supports WPP’s response.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	No
Document Name	
Comment	
Based on our comments in response to Questions above, BC Hydro suggests that implementing regulatory requirements to conduct energy reliability assessments can be achieved in a more cost-effective manner by eliminating duplication and overlap with other currently effective standards.	
Likes 0	
Dislikes 0	
Response	

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
Eliminating duplication and overlap with other standards would minimize bureaucracy and allow entities to comply with BAL-007 in a more cost-effective manner. For more details, see our response to Questions 3 and 7.	
Likes 0	
Dislikes 0	
Response	

Reed Adam - Seattle City Light - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

We are not aware of any analysis or study determining that this proposal is cost-effective, and therefore do not support this statement. Since the proposed standard requires the BA to be responsible to meet the ERA studies, it will most likely require the hiring of specialized skill sets that are not currently on staff. This can have a significant cost impact to BAs when the resource adequacy analyses are shifted from the Resource Planners to the BAs. The cost/benefit has not been articulated by the Drafting Team, and when this question was asked during a Drafting Team workshop, the Drafting Team admitted there was no analysis for cost effectiveness.
BAs, if given the opportunity, will try and pool their resources and create Emergency Energy Plans and form Resource Adequacy Pools. The current proposed BAL-007 does not provide the ability to do that and will therefore be a burden on many BAs.

Likes 0	
Dislikes 0	

Response

Michael Jang - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

SCL is in support and alignmnet with WPP's & Idaho's submitted comments.

Likes 0	
Dislikes 0	

Response

Daren Brubaker - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

I agree with the comments provided by Western Power Pool.

Likes 0	
Dislikes 0	

Response

Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seattle City Light agrees with WPP Submitted Comment.	
Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Idaho Power agrees with WPP's response to this question, shown below. We are not aware of any analysis or study determining that this proposal is cost-effective, and therefore do not support this statement. Since the proposed standard requires the BA to be responsible to meet the ERA studies, it will most likely require the hiring of specialized skill sets that are not currently on staff. This can have a significant cost impact to BAs when the resource adequacy analyses are shifted from the Resource Planners to the BAs. The cost/benefit has not been articulated by the Drafting Team, and when this question was asked during a Drafting Team workshop, the Drafting Team admitted there was no analysis for cost effectiveness. BAs, if given the opportunity, will try and pool their resources and create Emergency Energy Plans and form Resource Adequacy Pools. The current proposed BAL-007 does not provide the ability to do that and will therefore be a burden on many BAs.	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
No Additional Comments	
Likes 0	

Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 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	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No comment on cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	
Document Name	
Comment	
PNM does not have a comment or answer to this question at this time.	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO answers "No." (We had difficulty entering our comments into the SBS.) MISO supports the SRC comments. BAL-007 is currently substantively duplicative of EOP-011, TOP-002, and IRO-014 while simultaneously imposing additional administrative burdens that do not enhance system reliability. In addition, the standard presumes that BAs have access to fuel-related information that they do not possess and currently have no cost-effective method of obtaining. Addressing the information provision issues and eliminating duplication and overlap with other standards would minimize bureaucracy and allow entities to comply with BAL-007 in a more cost-effective manner. For more details, see our response to Questions 3, 7, and 9.	
Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	

Comment
Duke Energy’s vision is a highly reliable and secure bulk power system and will therefore not comment on cost-effectiveness.

Likes 0	
Dislikes 0	

Response

9. BAL-007-1 Near-term ERAs: Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	

Idaho Power agrees with WPP's response to this question, shown below.

In general, the need for Energy Assurance with Energy-Constrained Resources is understood. The drafting team has worked hard to address the needs to ensure energy adequacy and has invested a lot of time discussing and addressing concerns in the development of this standard. It is difficult to support the proposed standard because it is not performance-based and introduces a lot of administrative processes. It introduces a lot of compliance risk without enhancing BES reliability. The fill-in-the blank concept adds additional risk and incentivizes entities to meet the lowest common denominator of compliance, rather than encouraging exceptionalism. The proposal may seem workable from a practicable sense, but when enforced, the standard has a lot of subjective language that will be problematic. Requiring BA's to be responsible for resource adequacy seems like the wrong functional home for the ERA when that was typically the role of the Resource Planners.

The drafting team should focus on a coordinated resource plan as the end goal. It should consider where some entities have already made progress in developing solutions to address energy adequacy, and it should not exclude those programs that are already in existence.

RCs who oversee large BAs and markets should not find the requirements in this proposal too onerous due to the economy of scale. RCs who oversee large numbers of BAs, on the other hand, will have challenges in meeting the review timelines. The RCs will also struggle to ensure that energy adequacy is sufficiently coordinated amongst the multiple BAs. Seams issues will need to be addressed where there are adjacent BAs and RCs competing for the same resources.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	

Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	
Document Name	
Comment	

Seattle City Light agrees with WPP Submitted Comment.

Likes 0	
Dislikes 0	
Response	

Daren Brubaker - Seattle City Light - 1,3,4,5,6	

Answer	
Document Name	
Comment	

I agree with the comments provided by Western Power Pool.

Likes 0	
Dislikes 0	

Response

Michael Jang - Seattle City Light - 1,3,4,5,6

Answer	
Document Name	
Comment	

SCL is in support and alignmnet with WPP's & Idaho's submitted comments.

Likes 0	
Dislikes 0	

Response

Reed Adam - Seattle City Light - 1,3,5,6 - WECC

Answer	
Document Name	
Comment	

In general, the need for Energy Assurance with Energy-Constrained Resources is understood. The drafting team has worked hard to address the needs to ensure energy adequacy and has invested a lot of time discussing and addressing concerns in the development of this standard. It is difficult to support the proposed standard because it is not performance-based and introduces a lot of administrative processes. It introduces a lot of compliance risk without enhancing BES reliability. The fill-in-the blank concept adds additional risk and incentivizes entities to meet the lowest common denominator of compliance, rather than encouraging exceptionalism. The proposal may seem workable from a practicable sense, but when enforced, the standard has a lot of subjective language that will be problematic. Requiring BA’s to be responsible for resource adequacy seems like the wrong functional home for the ERA when that was typically the role of the Resource Planners.
The drafting team should focus on a coordinated resource plan as the end goal. It should consider where some entities have already made progress in developing solutions to address energy adequacy, and it should not exclude those programs that are already in existence.
RCs who oversee large BAs and markets should not find the requirements in this proposal too onerous due to the economy of scale. RCs who oversee large numbers of BAs, on the other hand, will have challenges in meeting the review timelines. The RCs will also struggle to ensure that energy adequacy is sufficiently coordinated amongst the multiple BAs. Seams issues will need

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Duke Energy supports proposed EEI language modifications for Question 9.

Duke is also supportive of the EEI comments regarding R10 and the edits to that requirement. Additionally, R10 requires the RC to act upon receipt of a notification from a BA in its footprint 'per Requirement R8'. This appears to be an error in the language of R10 after the renumber of prior requirements. The reference to R8 should be modified to be R9 since that is the requirement in which the BA *implements* the Operating Plan(s).

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

Purpose: There appears to be a word missing in the Purpose statement (page 3 of 12). Previously this was "assess and mitigate."

"To ______ the risks associated with Energy Emergencies in the near-term time horizon and take appropriate actions…"

Requirement R10 requires the BA to notify the RC and then the RC must notify entities with a role and neighboring RCs. This is both a duplicative and non-value-added step that should be modified to eliminate overlap and duplication with IRO-014, R3 and align with TOP-002, R5 as:

· IRO-014, R3 already requires the RC to notify other RCs of expected Emergencies.

IRO-014, R3. Each Reliability Coordinator, *upon identification of an expected* or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators.

· TOP-002-5, R5 already requires BAs to notify entities with a role in their Operating Plan(s)

TOP-002-5, 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).

The MRO NSRF recommends the SDT modify BAL-007, R10 as follows:

(please see attached document)	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO answers "No." (We had difficulty entering our comments into the SBS.)

Purpose: There appears to be a word missing in the Purpose statement (page 3 of 12).

"To ______ the risks associated with Energy Emergencies in the near-term time horizon and take appropriate actions…"

The BAL-008 purposes statement does not appear to be missing this word, as it begins with "To assess the risks associated…"

Requirement R10 imposes notification requirements on BAs and RCs. This is a duplicative and non-value-added step that is already addressed by IRO-014, R3 and TOP-002, R5:

IRO-014, R3 already requires the RC to notify other RCs of expected Emergencies.

IRO-014, R3. Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators.

TOP-002-5, R5 already requires BAs to notify entities with a role in their Operating Plan(s)

TOP-002-5, 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).

Consequently, MISO recommends the SDT remove BAL-007, R10:

Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	
Document Name	
Comment	

DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	
Document Name	
Comment	
The VSL Table for Requirement R9 identifies a High Severity Level if a BA fails to implement an Operating Plan for forecasted conditions per R8. R9 only obligates the BA to implement an Operating Plan for Energy Emergencies that meet the EEA1, EEA2 and EEA3 definitions. Recommend revising for consistency.	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

N/A	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	
Document Name	
Comment	
PNM supports EEI recommended changes to the BAL-007-1 purpose statement and R10.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion	
Answer	
Document Name	
Comment	
Dominion Energy is concerned that the communications required for R10 will lead to communication overload for the RC and for the entities that the RC is required to communicate with. This communication should be handled within the TOP-002 timeframe.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	

LG&E & KU agree with comments provided by EEI, with the following additional feedback on the wording for consistency:

- Page 4: B (R1) (1.3.3) – Capitalize "Constraints" and "Load" to signify reference to a NERC defined term: "1.3.3. Transmission c**C**onstraints that limit the ability of generation to deliver their output to load."
- Page 4: B (R2) (2.2.1) – Change "…energy supply contingency" to "…energy supply Contingency" to signify reference to a NERC defined term.
- Page 4: B (R2) (2.2.2) – Change "…fuel supply contingency" to "…fuel supply Contingency" to signify reference to a NERC defined term.
- Page 5: B (R4) – Change "The Balancing Authority…" to "Each Balancing Authority…" to match language in the rest of the document.
- Page 5: B (M4) – Add reference to Requirements R1 through R3 to match wording in R4. Add reference to 24 calendar months to match wording in R4. Change to: "Each Balancing Authority shall have evidence that it reviewed and updated, if necessary, its near-term ERA process, Scenarios or methods, Operating Plan(s) documented under Requirement R1 through R3 at least once every 24 calendar months, in accordance with Requirement R4."
- Page 5: B (M6) – Change "…the results of the review in accordance…" to "…the results of the review within 60 calendar days receiving a submittal from Requirement R6" to add reference to timeline.
- Page 5: B (M7) – Change "…resubmitted information to its Reliability Coordinator in accordance with…" to "…resubmitted updated information to its Reliability Coordinator within 60 calendar days of receipt of notice from Requirement R7" to add reference to timeline.
- Page 9: Violation Severity Table (R4) (High Violation) – Change "…but failed to update within 24 months" to "…but failed to update, *if necessary*, within 24 *calendar* months" to match wording in R4.
- Page 9: Violation Severity Table (R4) (Severe Violation) – Remove "…to the Reliability Coordinator" since R4 does not reference providing the Reliability Coordinator as that is included in R5.
- Page 9: Violation Severity Table (R5) (High Violation) – Change "…but failed to submit to the Reliability Coordinator within 24 months" to "…but failed to submit to the Reliability Coordinator within 24 *calendar* months" to match wording in R5.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

To align with NERC's Reliability Principles, BPA believes NERC drafting teams should strive to make reliability standards as clear as possible, especially regarding each responsible entity's authorities and responsibilities. BPA's understanding is that NERC is relying on TOP-003-5 for a Balancing Authority's (BA) authority to require the information needed to conduct the Energy Reliability Assessments under proposed BAL-007-1 and BAL-008-1. However, it's not clear the proposed standards are utilizing a BA's authority to require information under TOP-003-5. It requires an entity to refer to another suite of reliability standards to find requirements that could potentially empower a BA to require the necessary information, and put other entities on notice that they must provide the required information.

For clarity and effectiveness of the proposed standards, BPA suggests revising the Technical Rationale document by outlining a BA's authority to request data, and the responsibility/obligation for other entities to provide data via TOP-003-5. By issuing a clarification that TOP-003 does apply, NERC could empower BAs to obtain the data they need, as BPA believes TOP-003 intended.

Given that the fuel and future dispatch level of generation in current bilateral markets of the Pacific Northwest is considered 'market sensitive' information, generator owners and operators may not be willing to share such information with BAs or Transmission System Providers. As a result, the standards need to make absolutely clear that providing such information is required

Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	
Document Name	
Comment	
In the BAL-007-1 standard, under A. Introduction, 3. Purpose, CHPD recommends adjusting the language to something like "Assess the risks associated with…"	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company supports the EEI comments and agrees with the EEI language changes to the Purpose statement.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	
Document Name	

Comment

TEPC agrees with EEI's comments - EEI does not agree that the language currently contained in the purpose statement for BAL-007-1 is sufficiently clear. And while we do not disagree with the last sentence in the purpose, it does not provide any meaningful value to the purpose.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	
Document Name	

Comment

In general, the need for Energy Assurance with Energy-Constrained Resources is understood. The drafting team has worked hard to address the needs to ensure energy adequacy and has invested a lot of time discussing and addressing concerns in the development of this standard. It is difficult to support the proposed standard because it is not performance-based and introduces additional administrative processes. It also introduces compliance risk without enhancing BES reliability. The fill-in-the blank concept adds additional risk and incentivizes entities to meet the lowest common denominator of compliance, rather than encouraging exceptionalism. The proposal may seem workable from a practicable sense, but when enforced, the standard has a lot of subjective language that will be problematic. Requiring BA's to be responsible for resource adequacy seems like the wrong functional home for the ERA when that was typically the role of the Resource Planners.

The drafting team should focus on a coordinated resource plan as the end goal. It should consider where some entities have already made progress in developing solutions to address energy adequacy, and it should not exclude those programs that are already in existence.

RCs who oversee large BAs and markets should not find the requirements in this proposal too onerous due to the economy of scale. On the other hand, RCs who oversee large numbers of BAs, will have challenges in meeting the review timelines. The RCs will also struggle to ensure that energy adequacy is sufficiently coordinated amongst the multiple BAs. Seams issues will need to be addressed where there are adjacent BAs and RCs competing for the same resources.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	

WECC offers the following:

It appears the Purpose of the Standard is missing a term. Suggest adding “identify” after “To” (“To identify the risks……..”). It would be clearer to use language already used in other Standards—example in 1.3.2. what is consider “operations”? That is the question Regional Entities will get asked as it is not clear what the DT expectations are here. Using “sufficient” and “credible” equates to professional judgement being questioned just to determine how an entity determined what “sufficient” and “credible” means to an entity. Regional Entities will get asked what their version of “sufficient” and “credible” is to meet compliance. The Technical Rationale provides some examples which is good but will not cover the spectrum. It will be difficult to ascertain what is “sufficient” and “credible” in a consistent manner by entities and, perhaps, Regional Entities.

The Evidence Retention section needs to be addressed to reflect the time period within the particular Requirements. Six months is insufficient retention for Requirement R4 and Requirement R5. The boilerplate language about other evidence is not realistic in these cases. In order to capture effective evidence a BA and RC would need to be audited within 6 months of actions called out in R4 and R5.   Additionally, if an EEA is called as a result of an ERA it potentially may trigger a compliance monitoring tool to evaluate compliance to these Requirements because of the restrictive data retention timeframe.

High VSL for R2 is set to create tension between entities and NERC in determining what is sufficient and what is credible. VSLs for R4/R5 needs to add “calendar” in front of months. Severe VSL for R10 references R8 but should reference R9.

R7 High/Severe VSL- Should it read “The Balancing Authority addressed **the** reliability risks…”? What happens if the BA does not address all the reliability risks identified? Severe VSL should reference R5 not R4.

R10 VSLs should clearly indicate that if a BA is contacted by the TOPs are not there is a reliability concern and possible a violation. Suggest adding “one or more” in front of TOP.

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	

Ameren supports MISO's comments on this project.

Likes 0	
Dislikes 0	

Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	
Document Name	
Comment	
R10 requires the BA to notify the RC. This is duplicative with IRO-014, R3 and TOP-002-5, R5. It is recommended that R10 is removed from BAL-007.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 9	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed that an action verb is missing from the purpose statement of BAL-007-1. Texas RE recommends the following (in bold): Purpose: To **evaluate** the risks associated with Energy Emergencies in the near-term time horizon and take appropriate actions to address identified risk. As the Bulk-Power System becomes more reliant upon energy-constrained and variable resources, traditional capacity-based planning methods and strategies might not identify energy-related risks to reliable System operation. With the addition of Requirement R5, Requirement R10 should reference Requirement R9 instead of Requirement R8, which is the near-term ERAs and Requirement R9 refers to implementing an Operating Plan(s) based on the circumstances.	
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 endorses the comments provided by the Western Power Pool.

Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
Answer	
Document Name	
Comment	
Exelon does not oppose BAL-007, we support EEI's comments to clarify the Purpose statement.	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	
Document Name	
Comment	
The Purpose statement is missing a word or something. Maybe it should read “To mitigate the risks associated …”.	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	
Document Name	
Comment	
Supporting EEI comments.	

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC

Answer	
Document Name	

Comment

HQ recognizes that the work the drafting team has put in the development of these standards and is supportive of performing seasonal studies. However, we are concerned that certain requirements as they are written add an unnecessary burden in the process.

R3 : We suggest adding the following precision in bold:

Each Balancing Authority shall document and maintain one or more Operating Plan(s) to minimize **the impact** of forecasted Energy Emergencies as identified in the near-term ERA, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s).

R4 : this requirement is redundant with R1, R2 and R3. All those processes, Scenarios and method shall be maintained.

Likes 0	
Dislikes 0	

Response

Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6

Answer	
Document Name	

Comment

PSE agrees with WPP’s response to this question. Puget Sound Energy agrees with the goal of reducing Energy Emergencies during operations. There is a need for a mechanism for assessing resource adequacy and ensuring capacity during real time. PSE would like the standard to allow for regional assessment and coordination to meet the intent. In the Pacific Northwest there are a large number of Balancing Authorities with some being generation deficient and others having large generation surplus. Allowing for coordination and regional assessment would be more effective and provide greater benefit to our customers.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	
EEI does not agree that the language currently contained in the purpose statement for BAL-007-1 is sufficiently clear. And while we do not disagree with the last sentence in the purpose, it does not provide meaningful value to the purpose. To address our concerns, we offer the following proposed changes to the Purpose statement: **Purpose: To assess, report and plan to address energy constraints** in the near-term time horizon.	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	
Document Name	
Comment	
Puget Sound Energy (PSE) agrees with WPP's response to this question. Additional PSE comments are shown below. PSE agrees with the goal of reducing Energy Emergencies during operations. There is a need for a mechanism for assessing resource adequacy and ensuring capacity during real time. PSE would like the standard to allow for regional assessment and coordination to meet the intent. In the Pacific	

Northwest there are a large number of Balancing Authorities with some being generation deficient and others having large generation surplus. Allowing for coordination and regional assessment would be more effective and provide greater benefit to our customers.

Likes 0	
Dislikes 0	

Response

Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6

Answer	
Document Name	

Comment

Seminole agrees with FRCC's comments below

The FRCC agrees with and supports the Edison Electric Institute (EEI) comments on question #9:
EEI does not agree that the language currently contained in the purpose statement for BAL-007-1 is sufficiently clear. And while we do not disagree with the last sentence in the purpose, it does not provide meaningful value to the purpose. To address our concerns, we offer the following proposed changes to the Purpose statement:
Purpose: To assess, report and plan to address the risks associated with Energy Emergencies energy constraints in the near-term time horizon and take appropriate actions to address identified risk. As the Bulk-Power System becomes more reliant upon energy-constrained and variable resources, traditional capacity-based planning methods and strategies might not identify energy-related risks to reliable System operation.

Likes 0	
Dislikes 0	

Response

LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)

Answer	
Document Name	

Comment

FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

The BAL-007-1 Draft 2 “Purpose” statement is missing a verb in the first sentence. Currently as written it states, “To the risks associated with Energy Emergencies….” The SDT should consider revising to state “To *identify* the risks associated with Energy Emergencies…”

Additionally, in the Purpose Statement and Requirement 1, the term "near-term time horizon" is not listed in the NERC glossary of terms or in the NERC Time Horizon criteria and referenced in the standard. The SDT should consider revising “near-term time horizon” to "near-term time period" to avoid confusion with NERC defined Time Horizons.

Lastly, the administrative effort needed to implement BAL-007-1 may not work for all entities and will create administrative burdens for Balancing Authorities whose responsibility is to integrate resources, maintain load-interchange-generation balance and supports Interconnection frequency in real time. If Balancing Authorities are to perform near-term ERAs, it may create an added layer of complexity to day-to-day operational challenges. Additionally, data information needed to perform near-term ERAs such as forecasted Demand and Resource capability and deliverability may not be available nor provided to the Balancing Authority during a near-term (5 days to 6 weeks) time period and furthermore circumstances may change in Real-time.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance

Answer	
Document Name	

Comment

Purpose: There appears to be a word missing in the Purpose statement (page 3 of 12).

“To _______ the risks associated with Energy Emergencies in the near-term time horizon and take appropriate actions…”

The BAL-008 purposes statement does not appear to be missing this word, as it begins with “To assess the risks associated…”

Requirement R10 imposes notification requirements on BAs and RCs. This is a duplicative and non-value-added step that is already addressed by IRO-014, R3 and TOP-002, R5:

• IRO-014, R3 already requires the RC to notify other RCs of expected Emergencies.

IRO-014, R3. Each Reliability Coordinator, upon identification of an expected or actual Emergency in its Reliability Coordinator Area, shall notify other impacted Reliability Coordinators.

• TOP-002-5, R5 already requires BAs to notify entities with a role in their Operating Plan(s)

TOP-002-5, 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).

Consequently, the SRC recommends the SDT remove BAL-007, R10:

R10. Each Reliability Coordinator, within 24 hours of receiving a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R8, shall notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators of the forecasted condition(s), and the Balancing Authority's Operating Plan(s).

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

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

Likes 0	
Dislikes 0	

Response

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	
Document Name	

Comment

The FRCC agrees with and supports the Edison Electric Institute (EEI) comments on question #9: EEI does not agree that the language currently contained in the purpose statement for BAL-007-1 is sufficiently clear. And while we do not disagree with the last sentence in the purpose, it does not provide meaningful value to the purpose. To address our concerns, we offer the following proposed changes to the Purpose statement:

Purpose: To assess, report and plan to address energy constraints in the near-term time horizon.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	

Answer	
Document Name	
Comment	

See comments submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	
Response	

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO

Answer	
Document Name	
Comment	

NIPSCO supports MISO's feedback.

Likes 0	
Dislikes 0	
Response	

Chance Back - Muscatine Power and Water - 1,3,5,6

Answer	
Document Name	
Comment	

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	
Response	

George E Brown - Pattern Operators LP - 5

Answer	
Document Name	

Comment	
Pattern Energy supports Midwest Reliability Organization’s NERC Standards Review Forum’s (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

10. BAL-008-1 Seasonal ERAs: The SDT drafted BA-008-1 Requirement R1 to clarify what seasonal ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	

Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	No
Document Name	
Comment	
If two BAs define two different seasonal periods and one BA is dependent on energy transfers, would the neighboring BA have that energy to transfer if the seasonal timeframes are different?	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC	

Answer	No
Document Name	
Comment	

SMUD and BANC agree with the comments submitted by the Western Power Pool.

Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	2022-03_Unofficial Comment Form_BAL-007 and BAL-008_MRO NSRF_06-11-24rev.docx
Comment	

Some of the proposed language is unclear. Please clarify how these two concepts are intended to be applied: "does not need to include all hours in the seasonal period" and "its seasons…must cover an entire calendar year." Modify BAL-008 to reflect what is in the Technical Rationale, pages 5-6.

In addition, we have the same concerns with BAL-008 as those expressed for BAL-007 in our response to Question 2.

§ Since Part 1.4.3. includes 'resource capabilities,' that should encompass transmission limitations. Therefore, the MRO NSRF requests **Part 1.4.3 be stricken.** If the SDT disagrees with removing Part 1.4.3. altogether, then MRO NSRF proposes the following modification:

1.4.3. Transmission outages that bottle generation and limit the generator's output ability.

Likes 0	
Dislikes 0	
Response	

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8

Answer	No
Document Name	
Comment	

The FRCC proposes changing "depletion of fuel" within requirement 1.4.2 to "fuel supply" to ensure consistency with the language used in requirement R2 2.2.2.
The FRCC also would like to note that requirement 1.4.3 includes transmission constraints that limit the flow of MWs from the generator to the load in the ERA process and would require that a power flow study be performed for this constraint. This would add another level of complexity to

energy balancing study. The FRCC suggests removing the “delivery” language and instead should describe the constraints in terms of generator MW output ability.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

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

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance

Answer	No
Document Name	

Comment

Some of the proposed language is unclear. Specifically, the SRC requests clarification of how the following two concepts are intended to be applied: “does not need to include all hours in the seasonal period” and “its seasons…must cover an entire calendar year.” The SRC recommends that BAL-008 be modified to reflect what is in the Technical Rationale, pages 5-6.
In addition, the SRC’s concerns with BAL-007 R1 detailed in the SRC’s response to Question 2 also apply to BAL-008 R1.
The SRC also recommends removing Part 1.4.3, as Part 1.4.2 already includes ‘resource capabilities’ that would take into account transmission limitations

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No

Document Name	
Comment	

APS suggests specifying a minimum number of seasons to cover the time period. The SDT should consider specifying in R1.3, the frequency of seasonal ERAs as it is not sufficiently clear. If not specified, can a yearly assessment be performed? If no, what is preventing an entity to perform a single (yearly) seasonal assessment in R1?

Likes 0	
Dislikes 0	
Response	

LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)

Answer	No
Document Name	
Comment	

FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.

Likes 0	
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6

Answer	No
Document Name	
Comment	

Seminole agrees with FRCC's comments below

The FRCC proposes changing “depletion of fuel” within requirement 1.4.2 to “fuel supply” to ensure consistency with the language used in requirement R2 2.2.2.
The FRCC also would like to note that requirement 1.4.3 includes transmission constraints that limit the flow of MWs from the generator to the load in the ERA process and would require that a power flow study be performed for this constraint. This would add another level of complexity to energy balancing study. The FRCC suggests removing the “delivery” language and instead should describe the constraints in terms of generator MW output ability.

Likes 0	
Dislikes 0	
Response	

Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	

Puget Sound Energy agrees with WPP's response to this question, shown below.

The proposed language in BAL-008 regarding seasonal timelines is vague and ambiguous. There is no consistency in seasonal selection as proposed, and in practice this will lead to studies between BAs that are not coordinated, creating gaps in reliability. The seasonal ERA process should include how entities will ensure coordination with their neighboring entities for access to resources and fuel during a forecasted energy adequacy problem.

During enforcement, audit staff will tend to challenge entities who do not select traditional seasonal studies. They will apply subjective judgement if they disagree that the entity's defined seasons are more appropriate than traditionally defined seasons. Entities will struggle with compliance risk when the auditors evaluate the quality of the process.

The Drafting Team should consider, either sticking with traditional summer and winter seasonal studies, or defining the studies such as: Winter (November-Feb), Spring Shoulder (March-May), Summer (June-August) and Fall Shoulder (Sept-Oct). This would be more performance oriented and will assist entities in coordinating their seasonal studies for reliability.

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

While EEI generally supports the language proposed for Requirement R1, there are two issues that still need to be addressed. The first issue relates to the consistent use of language. In Requirement R1, subpart 1.4.2 uses the term "depletion of fuel", while in Requirement R2, subpart 2.2.2 "fuel supply" is used to address the same issue/concern. To address this concern, we suggest that "fuel supply" is a clearer term and aligns with the language used in the SAR.

EEI additionally notes that in subpart 1.4.3, it includes transmission constraints that limit the flow of MWs from the generator to the load in the ERA process indicates that a power flow study is expected to be performed. This would add more complexity to what is intended to be an energy balancing study. To address this concern, we suggest removing the "delivery" language and instead describe constraints in terms of generator MW output ability.

To address our Requirement R1 concerns we have included edits in boldface below:

R1. Each Balancing Authority shall document and maintain a process for conducting Energy Reliability Assessments (ERA) for the seasonal time horizon. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. The Balancing Authority shall define its seasons, which do not have to align with traditional seasonal definitions but must cover an entire calendar year.

1.2. The seasonal ERAs will be representative of the risks or conditions within each seasonal period. The Balancing Authority will determine the duration for each seasonal ERA to represent those risks or conditions and does not need to include all hours in the seasonal period.

1.3. The Balancing Authority shall define a periodicity for conducting the seasonal ERAs that provides for completion at least 30 calendar days prior to but no greater than 12 months before the beginning of each season.

1.4. The ERA process for seasonal ERAs must account for the following:

1.4.1. Forecasted or assumed Demand profiles;

1.4.2. Resource capabilities and operations, including fuel **supply**, variable energy resources, (e.g., wind, solar, and hydro) energy transfers between neighboring Balancing Authorities, and electric storage; and

1.4.3. **Local known BES transmission** constraints that limit the ability of **a generator to output expected MWs**.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

Some of the proposed language is unclear. Please clarify how these two concepts are intended to be applied: "*does not need to include all hours in the seasonal period*" and "*its seasons…must cover an entire calendar year*." Modify BAL-008 to reflect what is in the Technical Rationale, pages 5-6.

In addition, we have the same concerns with BAL-008 as those expressed for BAL-007 in our response to Question 2.

- Since Part 1.4.3. includes 'resource capabilities,' that should encompass transmission limitations. Therefore, NV Energy requests **Part 1.4.3 be stricken.** If the SDT disagrees with removing Part 1.4.3. altogether, then NV Energy proposes the following modification:

1.4.3. Transmission outages that bottle generation and limit the generator's output ability.

Likes 0	
Dislikes 0	

Response

Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	

PSE agrees with WPP's response to this question, shown below.

The proposed language in BAL-008 regarding seasonal timelines is vague and ambiguous. There is no consistency in seasonal selection as proposed, and in practice this will lead to studies between BAs that are not coordinated, creating gaps in reliability. The seasonal ERA process should include how entities will ensure coordination with their neighboring entities for access to resources and fuel during a forecasted energy adequacy problem.

During enforcement, audit staff will tend to challenge entities who do not select traditional seasonal studies. They will apply subjective judgement if they disagree that the entity's defined seasons are more appropriate than traditionally defined seasons. Entities will struggle with compliance risk when the auditors evaluate the quality of the process.

The Drafting Team should consider, either sticking with traditional summer and winter seasonal studies, or defining the studies such as: Winter (November-Feb), Spring Shoulder (March-May), Summer (June-August) and Fall Shoulder (Sept-Oct). This would be more performance oriented and will assist entities in coordinating their seasonal studies for reliability.

Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	No
Document Name	
Comment	

The reality for entities with large hydraulic reservoirs, as is the case for HQ, is completely different from "fuel" constraints. . Our Seasonal ERA begin two years from the current day.

Likes 0	
Dislikes 0	
Response	

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	

Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
We appreciate a BA has the flexibility to define its seasons. This again can lead to an interpretation during audit if not more clearly defined.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	

Tacoma Power endorses the comments provided by the Western Power Pool.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 10	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Please clarify conflicting concepts: “does not need to include all hours in the seasonal period” and “its season….must cover an entire calendar year”.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Nazra Gladu - Manitoba Hydro - 1,3,5,6

Answer	No
Document Name	

Comment

Manitoba Hydro supports comments of MRO NSRF.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Ameren supports MISO's comments on this project.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	No
Document Name	

Comment

WECC suggests placing "seasonal" in front of Energy Reliability Assessments to be consistent with suggested changes to BAL-007 and consistency throughout BAL-008. Similar concerns with language use here and EOP-011. "Fuel supply" and "availability" are consistent terms used in EOP-011. Also add "s" to "ERA". In 1.4.2, it is not clear what is meant by "and operations". Is the DT trying to capture projected availability of resources? Suggest

"Resource capabilities and availability including variable energy resource (e.g., wind, solar, hydro); Fuel supply concerns and inventory; energy transfers between neighboring Balancing Authorities; and electric storage; and". Should "electric storage" be BESS for consistency across Standards? Consider addressing hydro/wind/solar in the technical rationale to avoid limitations on future technologies	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
The proposed language in BAL-008 regarding seasonal timelines is vague and ambiguous. There is no consistency in seasonal selection as proposed, and in practice this will lead to studies between BAs that are not coordinated, creating gaps in reliability. The seasonal ERA process should include how entities will ensure coordination with their neighboring entities for access to resources and fuel during a forecasted energy adequacy problem. During enforcement, audit staff will tend to challenge entities who do not select traditional seasonal studies. They will apply subjective judgement if they disagree that the entity's defined seasons are more appropriate than traditionally defined seasons. Entities will struggle with compliance risk when the auditors evaluate the quality of the process. The Drafting Team should consider, either sticking with traditional summer and winter seasonal studies, or defining the studies such as: Winter (November-Feb), Spring Shoulder (March-May), Summer (June-August) and Fall Shoulder (Sept-Oct). This would be more performance oriented and will assist entities in coordinating their seasonal studies for reliability.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
TEPC agrees with EEI's comments - While EEI generally supports the language proposed for Requirement R1, there are two issues within BAL-008 that need to be addressed. The first issue relates to the lack of a minimum requirement for the seasons to be studied in Requirement R1, subpart 1.1. We do not agree that this should be open ended, instead we suggest a minimum of two seasons, noting that for most regions summer and winter are typically associated with the highest risk to the transmission system.	
Likes 0	
Dislikes 0	

Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company supports the EEI comments and agrees with the EEI language changes to R1.	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
CHPD supports WPP's response.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA's full response in question 15.	
Likes 0	
Dislikes 0	
Response	

Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	

Black Hills Corporation agrees with EEI’s comments, included here. While EEI generally supports the language proposed for Requirement R1, there are two issues that still need to be addressed. The first issue relates to the consistent use of language. In Requirement R1, subpart 1.4.2 uses the term “depletion of fuel”, while in Requirement R2, subpart 2.2.2 “fuel supply” is used to address the same issue/concern. To address this concern, we suggest that “fuel supply” is a clearer term and aligns with the language used in the SAR.

EEI additionally notes that in subpart 1.4.3, it includes transmission constraints that limit the flow of MWs from the generator to the load in the ERA process indicates that a power flow study is expected to be performed. This would add more complexity to what is intended to be an energy balancing study. To address this concern, we suggest removing the “delivery” language and instead describe constraints in terms of generator MW output ability.

To address our Requirement R1 concerns we have included edits in boldface below:

R1. Each Balancing Authority shall document and maintain a process for conducting Energy Reliability Assessments (ERA) for the seasonal time horizon. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

1.1. The Balancing Authority shall define its seasons, which do not have to align with traditional seasonal definitions but must cover an entire calendar year.

1.2. The seasonal ERAs will be representative of the risks or conditions within each seasonal period. The Balancing Authority will determine the duration for each seasonal ERA to represent those risks or conditions and does not need to include all hours in the seasonal period.

1.3. The Balancing Authority shall define a periodicity for conducting the seasonal ERAs that provides for completion at least 30 calendar days prior to but no greater than 12 months before the beginning of each season.

1.4. The ERA process for seasonal ERAs must account for the following:

1.4.1. Forecasted or assumed Demand profiles;

1.4.2. Resource capabilities and operations, including (*remove: **depletion of***) fuel **supply**, variable energy resources, (e.g., wind, solar, and hydro) energy transfers between neighboring Balancing Authorities, and electric storage; and

1.4.3. **Local** (*remove: **Transmission***) **known BES transmission** constraints that limit the ability of (*remove: **generation Facilities to deliver their output to Load***) **a generator to output expected MWs**.

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 recommended changes for BAL-008-1 R1.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the comments submitted by EEI.

Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Adopt R1.1 language. Duke Energy recommends the following modification to R1.4.3. to extend resources beyond the BA. R1.4.3. “Known BES transmission constraints that limit the ability to utilize expected resources.”	
Likes 0	
Dislikes 0	
Response	
Reed Adam - Seattle City Light - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

The proposed language in BAL-008 regarding seasonal timelines is vague and ambiguous. There is no consistency in seasonal selection as proposed, and in practice this will lead to studies between BAs that are not coordinated, creating gaps in reliability. The seasonal ERA process should include how entities will ensure coordination with their neighboring entities for access to resources and fuel during a forecasted energy adequacy problem.
During enforcement, audit staff will tend to challenge entities who do not select traditional seasonal studies. They will apply subjective judgement if they disagree that the entity's defined seasons are more appropriate than traditionally defined seasons. Entities will struggle with compliance risk when the auditors evaluate the quality of the process.
The Drafting Team should consider, either sticking with traditional summer and winter seasonal studies, or defining the studies such as: Winter (November-Feb), Spring Shoulder (March-May), Summer (June-August) and Fall Shoulder (Sept-Oct). This would be more performance oriented and will assist entities in coordinating their seasonal studies for reliability.

Likes 0	
Dislikes 0	

Response

Michael Jang - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

SCL is in support and alignmnet with WPP's & Idaho's submitted comments.

Likes 0	
Dislikes 0	

Response

Daren Brubaker - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

I agree with the comments provided by Western Power Pool.

Likes 0	
Dislikes 0	

Response

Chris Shultz - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	
Comment	

Seattle City Light agrees with WPP Submitted Comment.

Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	
Comment	

Idaho Power agrees with WPP's response to this question, shown below.

The proposed language in BAL-008 regarding seasonal timelines is vague and ambiguous. There is no consistency in seasonal selection as proposed, and in practice this will lead to studies between BAs that are not coordinated, creating gaps in reliability. The seasonal ERA process should include how entities will ensure coordination with their neighboring entities for access to resources and fuel during a forecasted energy adequacy problem.

During enforcement, audit staff will tend to challenge entities who do not select traditional seasonal studies. They will apply subjective judgement if they disagree that the entity's defined seasons are more appropriate than traditionally defined seasons. Entities will struggle with compliance risk when the auditors evaluate the quality of the process.

The Drafting Team should consider, either sticking with traditional summer and winter seasonal studies, or defining the studies such as: Winter (November-Feb), Spring Shoulder (March-May), Summer (June-August) and Fall Shoulder (Sept-Oct). This would be more performance oriented and will assist entities in coordinating their seasonal studies for reliability.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	

Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	

Document Name	
Comment	

The drafting team should clarify how the requirement to account for "depletion of fuel" should be applied to interruptions to gas supply and transportation. This is important to clarify because correlated failures of gas generators, often due to fuel supply and transportation constraints and interruptions, have been the primary contributing factor in all recent cold snap events that have led to FERC-NERC reports. The drafting team should clarify that assessments should include the expected unavaiability of gas generators, informed by past experience during winter peak demand periods, when accounting for "resource capabilities and operations," particularly for winter energy reliability assessments.

Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1

Answer	
Document Name	
Comment	

Support the MRO NSRF comments.

Likes 0	
Dislikes 0	
Response	

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	
Document Name	
Comment	

While ISO-NE believes R1 is sufficient, ISO-NE requests that the SDT provide clarification to R1.2 and an explanation why the seasonal ERA does not need to include all hours in the seasonal period?

Suggest changing R1.1. to

1.1 The Balancing Authority shall define its seasons as follows:

1.1.1 Must include a minimum of two (2) seasons, which do not have to align with traditional seasonal definitions

1.1.2 Seasons must encompass an entire year.

Suggest changing R1.4.1. to “Forecasted demand profiles” Suggest changing R1.4.2 “depletion of fuel” to “fuel supplies”

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	

Comment
MISO answers "No." (We had difficulty entering our comments into the SBS.) Some of the proposed language is unclear. Specifically, we request clarification of how the following two concepts are intended to be applied: “*does not need to include all hours in the seasonal period*” and “*its seasons…must cover an entire calendar year*.” MISO recommends BAL-008 be modified to reflect what is in the Technical Rationale, pages 5-6. In addition, MISO’s concerns with BAL-007 R1 detailed in our response to Question 2 also apply to BAL-008 R1. Finally, we recommend removing **Part 1.4.3,** as Part 1.4.2 already includes ‘resource capabilities’ that would take into account transmission limitations.

Likes 0	
Dislikes 0	

Response

11. BAL-008-1 Seasonal ERAs: The SDT drafted BAL-008-1 Requirements R2 through R13 based on industry feedback regarding seasonal ERAs. Do you agree with the proposed requirements? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

Idaho Power agrees with WPP's response to this question, shown below.

R2: In general, R2 is vague and ambiguous. It amounts to a fill-in-the-blank standard which puts entities in a position where they will be held accountable for their own practices. This incentivizes companies to meet minimum criteria to not risk potential non-compliance. Entities exceeding expectations will be rewarded with additional compliance risk. R2 has no performance measurements associated and no minimum level of performance. NERC Standards should be performance based, not administrative. Documentation of Scenarios, methods, and the rationales will result in subjective enforcement and issues related to quality. Entities will be exposed to compliance risk for administrative mistakes and errata errors, rather than poor performance that can put the BES in risk. The drafting team is encouraged to consider what a minimal acceptable performance should be for seasonal ERAs.

The Drafting Team utilizes the term "credible" several times. Credible is a subjective term and what is credible to one entity (or auditor), may not be credible to another. This leaves the entity in a very difficult situation when being audited against R2.

R3: R3 requires the BA to document and maintain one or more Operating Plans to minimize forecasted Energy Emergencies identified through the ERA, but they are not required to implement plans when an Energy Emergency is identified. BAs maintain Operating Plans under TOP-002, and it is not clear if these can be the same or different Operating Plans identified in TOP-002. TOP-002 deals with next-day operations and it is confusing if the proposed BAL-008 Operating Plans are superseded by next day or real-time Operation Plans.

R3 uses the phrase "...minimize forecasted Energy Emergencies..." the term "minimize" is subjective and not measurable. Though the intent of the drafting team seems clear, enforcement it will be up to the auditor to determine if the entity is effectively minimizing identified Energy Emergencies.

The measures in both R2 and R3 give little guidance to an entity, or the auditor, as to what evidence is sufficient. The two requirements are administrative and require documents for compliance, but do not set a minimum criterion for performance. This encourages minimal compliance, and not acceptable levels of performance.

R4: R4 properly identifies a performance-based criteria.

R5: R5 properly identifies a performance-based criteria.

R6: R6 is properly worded and is performance-based.

R7: R7 requires the entity to review and update its seasonal ERA process "if needed". This puts a burden on the entity to prove when and updated is warranted. During enforcement, if a document is not updated regularly, the auditor will assume it is not being maintained properly. Entities will have to explain why there was no need to update the documentation. Auditors will default to looking for errata errors in the documentation. This leads to zero defect compliance practices that NERC has been trying to distance itself from with better written standards.

R8: In R8 the entities are asked to "...provide [their] seasonal ERA process, Scenarios or methods, and Operating Plans(s)... to the RC at least once every 24 Calendar Months, on a mutually agreed schedule." R1 and R2 require the BAs to develop a seasonal ERA process and Scenarios, and R3 requires the entity to create Operating Plans based on the ERA process. The Operating Plans are done each season identified by the individual BA. This makes the product from R3 only relevant to the season it is looking at. Requiring entities to provide the "...Scenarios or methods, and Operating Plans..." at least once every 24 calendar months is confusing and provides no benefit since the Scenarios and operating plans will be stale. The submission of the ERA process under R1 makes sense, since it is supposedly reviewed and updated in that period; but providing Scenarios, methods and Operating Plans every 24 months is of no use. It is recommended that ONLY the updated ERA process be submitted to the RC every 24 calendar months. Seasonal assessment results should be provided no later than 30 days prior to the start of the season, and operating plans should not be included.

The ERA process submission to the RC should require resubmission after any revision is made to the process. The current proposal allows an entity to submit its plan to the RC, then if they update their document, it doesn't have to be resubmitted until the next 24-month submittal. Other NERC Standards require entities to submit revised processes within 30 or 60 days of any update.

R9: The lead in sentence of R9 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider a: "The Reliability Coordinator, within 60 days of receipt of the information identified in Requirement R9, shall:"

R10: The lead in sentence of R10 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider: "The Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit updated information within the schedule specified by the Reliability Coordinator."

R11: It is not clear why the Drafting Team elected to put a follow-on requirement to R1 so low in the list of requirements. R11 should be combined with R2 or R3 as a performance requirement the R1 requirement. Alternatively, R11 could be moved up to R3, and renumbering the current requirements R3 through R13.

R12: R12 is not needed, since BAL-007 requirements require short-term assessments and operating plans, which would address and override any plans made over 6 months out in a seasonal ERA.

R13: R13 is confusing, since it is requiring 7 days of notice of the implementation of an operating plan that would most likely be implemented in, or very close to, real-time. Fundamentally, operation plans from seasonal studies will be overridden by BAL-007 operating plans in the near-term.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	

Response

Chris Shultz - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

Seattle City Light agrees with WPP Submitted Comment.

Likes 0	
Dislikes 0	

Response

Daren Brubaker - Seattle City Light - 1,3,4,5,6

Answer	No

Document Name	
Comment	
I agree with the comments provided by Western Power Pool.	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
SCL is in support and alignmnet with WPP's & Idaho's submitted comments.	
Likes 0	
Dislikes 0	
Response	
Reed Adam - Seattle City Light - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

R2: In general, R2 is vague and ambiguous. It amounts to a fill-in-the-blank standard which puts entities in a position where they will be held accountable for their own practices. This incentivizes companies to meet minimum criteria to not risk potential non-compliance. Entities exceeding expectations will be rewarded with additional compliance risk. R2 has no performance measurements associated and no minimum level of performance. NERC Standards should be performance based, not administrative. Documentation of Scenarios, methods, and the rationales will result in subjective enforcement and issues related to quality. Entities will be exposed to compliance risk for administrative mistakes and errata errors, rather than poor performance that can put the BES in risk. The drafting team is encouraged to consider what a minimal acceptable performance should be for seasonal ERAs.
The Drafting Team utilizes the term “credible” several times. Credible is a subjective term and what is credible to one entity (or auditor), may not be credible to another. This leaves the entity in a very difficult situation when being audited against R2.
R3: R3 requires the BA to document and maintain one or more Operating Plans to minimize forecasted Energy Emergencies identified through the ERA, but they are not required to implement plans when an Energy Emergency is identified. BAs maintain Operating Plans under TOP-002, and it is not clear if these can be the same or different Operating Plans identified in TOP-002. TOP-002 deals with next-day operations and it is confusing if the proposed BAL-008 Operating Plans are superseded by next day or real-time Operation Plans.
R3 uses the phrase “…minimize forecasted Energy Emergencies…” the term “minimize” is subjective and not measurable. Though the intent of the drafting team seems clear, enforcement it will be up to the auditor to determine if the entity is effectively minimizing identified Energy Emergencies.
The measures in both R2 and R3 give little guidance to an entity, or the auditor, as to what evidence is sufficient. The two requirements are

administrative and require documents for compliance, but do not set a minimum criterion for performance. This encourages minimal compliance, and not acceptable levels of performance.
R4: R4 properly identifies a performance-based criteria.
R5: R5 properly identifies a performance-based criteria.
R6: R6 is properly worded and is performance-based.
R7: R7 requires the entity to review and update its seasonal ERA process “if needed”. This puts a burden on the entity to prove when and updated is warranted. During enforcement, if a document is not updated regularly, the auditor will assume it is not being maintained properly. Entities will have to explain why there was no need to update the documentation. Auditors will default to looking for errata errors in the documentation. This leads to zero defect compliance practices that NERC has been trying to distance itself from with better written standards.
R8: In R8 the entities are asked to “…provide [their] seasonal ERA process, Scenarios or methods, and Operating Plans(s)… to the RC at least once every 24 Calendar Months, on a mutually agreed schedule.” R1 and R2 require the BAs to develop a seasonal ERA process and Scenarios, and R3 requires the entity to create Operating Plans based on the ERA process. The Operating Plans are done each season identified by the individual BA. This makes the product from R3 only relevant to the season it is looking at. Requiring entities to provide the “…Scenarios or methods, and Operating Plans…” at least once every 24 calendar months is confusing and provides no benefit since the Scenarios and operating plans will be stale. The submission of the ERA process under R1 makes sense, since it is supposedly reviewed and updated in that period; but providing Scenarios, methods and Operating Plans every 24 months is of no use. It is recommended that ONLY the updated ERA process be submitted to the RC every 24 calendar months. Seasonal assessment results should be provided no later than 30 days prior to the start of the season, and operating plans should not be included.
The ERA process submission to the RC should require resubmission after any revision is made to the process. The current proposal allows an entity to submit its plan to the RC, then if they update their document, it doesn’t have to be resubmitted until the next 24-month submittal. Other NERC Standards require entities to submit revised processes within 30 or 60 days of any update.
R9: The lead in sentence of R9 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider a: “The Reliability Coordinator, within 60 days of receipt of the information identified in Requirement R9, shall:”
R10: The lead in sentence of R10 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider: “The Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit updated information within the schedule specified by the Reliability Coordinator.”
R11: It is not clear why the Drafting Team elected to put a follow-on requirement to R1 so low in the list of requirements. R11 should be combined with R2 or R3 as a performance requirement the R1 requirement. Alternatively, R11 could be moved up to R3, and renumbering the current requirements R3 through R13.
R12: R12 is not needed, since BAL-007 requirements require short-term assessments and operating plans, which would address and override any plans made over 6 months out in a seasonal ERA.
R13: R13 is confusing, since it is requiring 7 days of notice of the implementation of an operating plan that would most likely be implemented in, or very close to, real-time. Fundamentally, operation plans from seasonal studies will be overridden by BAL-007 operating plans in the near-term.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Duke Energy supports proposed EEI language modifications to R2, R3 and R9 for Question 11.

Also, R13 should be deleted from the proposed BAL-008 standard. The results of the seasonal ERA are more appropriately provided to the ERO as a part of its response to seasonal reliability assessments.

Additionally, the data sharing requirements in R6 should be modified to utilize the data content and format utilized by the RP. The Resource Planner should not be required to modify the content or format of data to solely support the needs of the BA.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

There is an incomplete framework for R4. Need a more defined way of obtaining data from the Generator Operators as described in our response to Question 13.

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy

Answer	No
Document Name	

Comment

DTE supports MISO's feedback

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5

Answer	No
Document Name	

Comment

The data requirements for seasonal ERAs per Requirement R4 may include market sensitive information and assumptions. Some of these assumptions may require synchronization between adjacent entities, and there may be subject to international agreements. BC Hydro suggests that a defined framework and possibly data sharing agreements would be required to enable the exchange of relevant information with other entities.

Requirement R7 mandates a 24 calendar months to review and update as necessary the R1 process, R2 Scenarios/methods, and R3 Operating Plan(s). This may constitute double-jeopardy, as failure to review and/or update may also constitute a possible noncompliance to the requirement to "maintain" the R1, R2, and R3 deliverables. BC Hydro recommends that R7 is not required, rather a measure of compliance be added in conjunction with the requirement to maintain under R1, R2, and R3.

Requirement R8 as written is vague and does not seem to provide value to reliability, particularly in case of Operating Plans, many of which would be obsolete on a 24-month provision timeframe. The Technical Rationale indicates that the intent is for the BAs and their respective RCs to have a mutually agreed protocol for the BC to provide updated R1, R2 and R3 documentation to the RC. BC Hydro recommends that R5 be revised to reflect the intent as stated in the Technical Rationale. Suggested wording provided below:

"R8 Each Balancing Authority and RC shall have and implement a documented protocol for the Balancing Authority to provide, at least once every 24 calendar months, its Reliability Coordinator with the near-term ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3."

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

See comments in question 13

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 recommended changes for BAL-007-1 R2, R3, R9, and R13.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments but has the additional concerns:

R2: For R2, usage of the word “credible” is subjective. This requirement should make clear that credibility of the Scenarios is for the BA to define and document. This language is pulled straight from the technical rationale for BAL-008-1. Recommend addition of “BA to define credible within their process”.

R6: Since this requirement is for seasonal ERAs, Same-Day Operations and Real-Time Operations should be removed from the time horizon.

R12/13: R12 and R13 do not seem appropriate for seasonal reliability assessments. BAL-007-1 addresses energy reliability in an appropriate timeframe where action should be taken. Recommend removal of these requirements.

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Black Hills Corporation - 1,3,5,6

Answer	No

Document Name	
Comment	

Black Hills Corporation agrees with EEI's comments. EEI does not oppose the changes made to Requirements R4, R5, R6, R7, R8, R10, R11 and R12 but we do have concerns with the proposed changes to R2, R3, R9 and R13.

Requirement R2 Concerns: EEI does not support language contained in subpart 2.3 because the BA should have sole authority to determine what constitutes "other scenarios with a credible risk". We additionally do not agree that it is necessary to include "or historical" within subpart 2.3 because the BA already has awareness of historical risks within their BA region and those risks factor into their assessment of what is a credible risk. To address our concerns, we offer the following changes to Requirement R2, subpart 2.3 (in boldface):

2.3. Other Scenarios with a credible (*remove:* ***or historical***) risk of occurring (*remove:* ***based on the best information available at the time of Scenario creation***) **as determined by the BA**."

Requirement R3 Concerns: While EEI appreciates the intent of the proposed language to minimize forecasted Energy Emergencies, the proposed language provides no clarity regarding this process. To address this concern, including language that makes it clear that the BA has sole discretion regarding when it is necessary to notify the RC of forecasted Energy Emergencies is needed. Such discretion would rightly provide due weight to the technical expertise of the BA allowing that functional entity to recognize when there is an imminent risk to the reliability of the BES and when it would be necessary to issue a notification under this Requirement.

R3: Each Balancing Authority shall document and maintain one or more Operating Plan(s) (*remove:* ***to minimize forecasted Energy Emergencies***) as identified in the seasonal ERA (*remove:* ***, including***) **that include** provisions for notifying the Reliability Coordinator of **a** forecasted Energy Emergency and the Operating Plan(s), **when deemed necessary**. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Requirement R9 Concerns: EEI notes that Requirement R9 cites certain RC actions related to Requirement R8. Requirement R8 is an administrative Requirement that simply obligates the BA to supply their seasonal ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. Under Requirement R9 the RC is obligated to review the R8 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days and therefore is administrative activity and should not have a VRF higher than Low.

Requirement R13 Concerns: EEI does not support the proposed language of Requirement R13 because of the following concerns:

1. For a seasonal forecasted Energy Emergency, obligating the RC to respond within 7 days when a seasonal forecasted Energy Emergency is unlikely to ever represent an imminent emergency is unjustified. EEI suggests 30 days as a more appropriate and reasonable timeframe.

2. Not all forecasted seasonal EEA need to be circulated. The RC needs to review the forecasted EEA and determine if it is credible. If not, they should return it to the BA with questions before circulating it to other BAs within their footprint and neighboring RCs.

3. EEI does not support a medium VRF for forecasted seasonal EEA given a seasonal Forecasted EEA does not have the same level of urgency as a seasonal forecasted EEA.

R13. Each Reliability Coordinator, **who receives notification of a forecasted seasonal Energy Emergency, pursuant to Requirement R3 that includes an implemented Operating Plan pursuant to Requirement R8 and evaluated as credible by the Reliability Coordinator; shall** within (*remove:* ***seven***) **thirty (30)** calendar days of receiving (*remove:* ***a***) **the** notification (*remove:* ***that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R8, shall***) notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of the forecasted condition(s) and the Balancing Authority's Operating Plan(s). **If the RC**

determines the forecasted seasonal Energy Emergency is not credible or they have questions, they shall transmit their concerns to the responsible BA for further review & discussion. [Violation Risk Factor: (*remove:* ***Medium***) **Low**] [Time Horizon: Operations Planning]	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Please see BPA's full response in question 15.	
Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
CHPD supports WPP's response.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company supports the EEI comments and agrees with the EEI language changes.	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
TEPC agrees with EEI's comments - EEI has concerns with the proposed changes to R2 (EEI does not support language contained in subpart 2.3 because the BA should have sole authority to determine what constitutes “other scenarios with a credible or historical risk”.), R3 (While EEI appreciates the intent of the proposed language to minimize forecasted Energy Emergencies, the proposed language provides no clarity regarding this process. To	

address this concern, including language that makes it clear that the BA has sole discretion regarding when it is necessary to notify the RC of forecasted Energy Emergencies is needed. Such discretion would rightly provide due weight to the technical expertise of the BA allowing that functional entity to recognize when there is an imminent risk to the reliability of the BES and worthy of notification under this Requirement), R9 (EEI notes that Requirement R9 cites certain RC actions related to Requirement R8. Requirement R8 is an administrative Requirement that simply obligates the BA to supply their seasonal ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. Under Requirement R9 the RC is obligated to review the R8 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days and therefore is administrative activity and should not have a VRF higher than Low.), and R13 (EEI suggests 30 days as a more appropriate and reasonable timeframe).

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

R2: In general, R2 is vague and ambiguous. It amounts to a fill-in-the-blank standard which puts entities in a position where they will be held accountable for their own practices. This incentivizes companies to meet minimum criteria to not risk potential non-compliance. Entities exceeding expectations will be rewarded with additional compliance risk. R2 has no performance measurements associated and no minimum level of performance. NERC Standards should be performance based, not administrative. Documentation of Scenarios, methods, and the rationales will result in subjective enforcement and issues related to quality. Entities will be exposed to compliance risk for administrative mistakes and errata errors, rather than poor performance that can put the BES in risk. The drafting team is encouraged to consider what a minimal acceptable performance should be for seasonal ERAs.

The Drafting Team utilizes the term “credible” several times. Credible is a subjective term and what is credible to one entity (or auditor), may not be credible to another. This leaves the entity in a very difficult situation when being audited against R2.

R3: R3 requires the BA to document and maintain one or more Operating Plans to minimize forecasted Energy Emergencies identified through the ERA, but they are not required to implement plans when an Energy Emergency is identified. BAs maintain Operating Plans under TOP-002, and it is not clear if these can be the same or different Operating Plans identified in TOP-002. TOP-002 deals with next-day operations and it is confusing if the proposed BAL-008 Operating Plans are superseded by next day or real-time Operation Plans.

R3 uses the phrase “…minimize forecasted Energy Emergencies…” the term “minimize” is subjective and not measurable. Though the intent of the drafting team seems clear, enforcement it will be up to the auditor to determine if the entity is effectively minimizing identified Energy Emergencies.

The measures in both R2 and R3 give little guidance to an entity, or the auditor, as to what evidence is sufficient. The two requirements are administrative and require documents for compliance, but do not set a minimum criterion for performance. This encourages minimal compliance, and not acceptable levels of performance.

R4: R4 properly identifies a performance-based criteria.

R5: R5 properly identifies a performance-based criteria.

R6: R6 is properly worded and is performance-based.

R7: R7 requires the entity to review and update its seasonal ERA process “if needed”. This puts a burden on the entity to prove when and updated is warranted. During enforcement, if a document is not updated regularly, the auditor will assume it is not being maintained properly. Entities will have to explain why there was no need to update the documentation. Auditors will default to looking for errata errors in the documentation. This leads to zero defect compliance practices that NERC has been trying to distance itself from with better written standards.

R8: In R8 the entities are asked to “…provide [their] seasonal ERA process, Scenarios or methods, and Operating Plans(s)… to the RC at least once every 24 Calendar Months, on a mutually agreed schedule.” R1 and R2 require the BAs to develop a seasonal ERA process and Scenarios, and R3 requires the entity to create Operating Plans based on the ERA process. The Operating Plans are done each season identified by the individual BA. This makes the product from R3 only relevant to the season it is looking at. Requiring entities to provide the “…Scenarios or methods, and Operating Plans…” at least once every 24 calendar months is confusing and provides no benefit since the Scenarios and operating plans will be stale. The submission of the ERA process under R1 makes sense, since it is supposedly reviewed and updated in that period; but providing Scenarios, methods and Operating Plans every 24 months is of no use. It is recommended that ONLY the updated ERA process be submitted to the RC every 24 calendar months. Seasonal assessment results should be provided no later than 30 days prior to the start of the season, and operating plans should not be included.

The ERA process submission to the RC should require resubmission after any revision is made to the process. The current proposal allows an entity to submit its plan to the RC, then if they update their document, it doesn’t have to be resubmitted until the next 24-month submittal. Other NERC Standards require entities to submit revised processes within 30 or 60 days of any update.

R9: The lead in sentence of R9 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider a: “The Reliability Coordinator, within 60 days of receipt of the information identified in Requirement R9, shall:”

R10: The lead in sentence of R10 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider: “The Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit updated information within the schedule specified by the Reliability Coordinator.”

R11: It is not clear why the Drafting Team elected to put a follow-on requirement to R1 so low in the list of requirements. R11 should be combined with R2 or R3 as a performance requirement the R1 requirement. Alternatively, R11 could be moved up to R3, and renumbering the current requirements R3 through R13.

R12: R12 is not needed, since BAL-007 requirements require short-term assessments and operating plans, which would address and override any plans made over 6 months out in a seasonal ERA.

R13: R13 is confusing, since it is requiring 7 days of notice of the implementation of an operating plan that would most likely be implemented in, or very close to, real-time. Fundamentally, operation plans from seasonal studies will be overridden by BAL-007 operating plans in the near-term.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	No
Document Name	

Comment

WECC believes the phrase “by a sufficient amount to stress the system within a range of credible situations” is ambiguous and will be applied inconsistently. Is varying conditions for an ERA intended to be sufficient enough to create an EEA level? There needs to be clarity in what may be expected in the rationales. Suggest “Include a rationale for the Scenarios or method of Scenario creation that includes support for criteria determined by the Balancing Authority for varying the following conditions.” Suggest changing “operations” in R2.2. to “availability”. Requirement 2.3 does not appear to be cohesive with the phrase “shall vary one or more of the following conditions…” Consider editing and adding as a second sentence in R2 as follows “Each Balancing Authority shall……….for use in performing near-term ERAs. Scenarios with a credible or historical risk of occurring may be used based on the best information available at the time of Scenario creation.” As written each BA would not have to “consider” the other Scenarios called out in 2.3 (as mentioned in the Technical Rational). The “Other Scenarios” may not be seen as a “following condition” which will cause confusion. The DT is correct in including previous historical Scenarios that stress the System as a basis for an ERA. Consider adding a 2.2.4 “Energy transfers between neighboring Balancing Authorities” to support 1.4 language.

R4/R5/R6- A data specification provision (and associated responsibilities) already exists in TOP-003. It is unclear what a Resource Planner would provide as they are looking at long-term plan (generally one year and beyond) for resource adequacy of specific loads within a Planning Authority/Planning Coordinator Area. That implies that data the Resource Planner has may not fit the seasonal ERA performance expectations (“at least 30 calendar days prior to but no greater than 12 months before the beginning of each season.”). The DT should consider either the PC or RC in terms of providing data that it may not already have for its “analysis functions” per TOP-003.

R7/R8- Similar to BAL-007. Operating Plans are likely to change from one winter to the next (as an example) and reviewing/providing those Operating Plans at least once every 24 months does not appear to support reliability. It is clear the process and considerations of Scenarios needs to be periodically reviewed.

R9- EOP-011 has a 30 calendar day timeline for Operating Plans associated with Energy Emergencies and is in conflict with this Requirements 60 calendar days. Suggest say “results” versus “information”. It is not clear how the RC will avoid risks. Is it reviewing the Operating Plans only? As noted, it would be reasonable to expect Operating Plans to fit the conditions noted in a near-term ERA which has a limited duration (up to six weeks). What Operating Plans would be provided and of what value would Operating plans be if 24 months old? The Operating Plans for an Energy Emergency are to be reviewed by the RC prior to implementation. If Operating Plans are only reviewed once every 24 months versus as developed (and updated) how could coordination occur? Additionally, may need to indicate “Notify the submitting Balancing Authority…” versus “each” in Part 9.2.

R10- While not in conflict with EOP-011, EOP-011 may set a timeframe for response that could exceed the 60 calendar days. What is the expectation for the DT as to how a BA will address the reliability risks? Especially if the reliability risk is a coordination issue? It appears that for coordination caused/resultant reliability risks the RC would need to clearly indicate actions so that there is not an infinite loop of actions and reactions. Also, by using “any” that means a BA could address only one and be compliant. If supporting reliability, the BA should address ALL the reliability risks identified. What recourse does a BA have if it cannot alleviate the risk?

R13- If implementing an Operating Plan is in Real-time what good is “seven calendar day” notification? An Operating Plan may be developed during the seasonal ERA but may not be implemented until the conditions actually exist. It is as if the Operating Plan based on an ERA is expected to perform an action at a date within the study period that is greater than 7 days ahead of Real-time.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Ameren supports MISO's comments on this project.

Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
A defined requirement to obtain data from Generator Operators is needed. Such as modification to TOP-003 as described in question 13.	
Likes 0	
Dislikes 0	

Response

Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 11	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power endorses the comments provided by the Western Power Pool.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1,3	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI	
Likes 0	
Dislikes 0	
Response	

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	No
Document Name	
Comment	
R1 : We suggest adding verbiage that allows some flexibility in the data requested:. For example, we suggest adding the text in bold below to R1.4.2. R1.4.2 : Resource capabilities and operations, **including pertinent data** such as depletion of fuel… R2.2.2 : Fuel/Resource supply contingency is not applicable in an hydraulic context such as Hydro-Quebec. [A1] R4 to R6 : These requirements should be placed in TOP-003 standard. R7 : This requirement is redundant with the "maintain" obligation state in R1, R2 and R3. R8 to R10 : When there is only one RC and BA in an Interconnexion, R8 to R10 should be not applicable. R11. We suggest adding the verb "implement" to R1 and R2, which would thus render this requirement unnecessary. " R1 Each Balancing Authority shall document, maintain and **implement** a process for conducting Energy Reliability Assessments …"	
Likes 0	
Dislikes 0	
Response	

Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	

PSE agrees with WPP's response to this question, shown below.

R2: In general, R2 is vague and ambiguous. It amounts to a fill-in-the-blank standard which puts entities in a position where they will be held accountable for their own practices. This incentivizes companies to meet minimum criteria to not risk potential non-compliance. Entities exceeding expectations will be rewarded with additional compliance risk. R2 has no performance measurements associated and no minimum level of performance. NERC Standards should be performance based, not administrative. Documentation of Scenarios, methods, and the rationales will result in subjective enforcement and issues related to quality. Entities will be exposed to compliance risk for administrative mistakes and errata errors, rather than poor performance that can put the BES in risk. The drafting team is encouraged to consider what a minimal acceptable performance should be for seasonal ERAs.

The Drafting Team utilizes the term "credible" several times. Credible is a subjective term and what is credible to one entity (or auditor), may not be credible to another. This leaves the entity in a very difficult situation when being audited against R2.

R3: R3 requires the BA to document and maintain one or more Operating Plans to minimize forecasted Energy Emergencies identified through the ERA, but they are not required to implement plans when an Energy Emergency is identified. BAs maintain Operating Plans under TOP-002, and it is not clear if these can be the same or different Operating Plans identified in TOP-002. TOP-002 deals with next-day operations and it is confusing if the proposed BAL-008 Operating Plans are superseded by next day or real-time Operation Plans.

R3 uses the phrase "...minimize forecasted Energy Emergencies..." the term "minimize" is subjective and not measurable. Though the intent of the drafting team seems clear, enforcement it will be up to the auditor to determine if the entity is effectively minimizing identified Energy Emergencies.

The measures in both R2 and R3 give little guidance to an entity, or the auditor, as to what evidence is sufficient. The two requirements are administrative and require documents for compliance, but do not set a minimum criterion for performance. This encourages minimal compliance, and not acceptable levels of performance.

R4: R4 properly identifies a performance-based criteria.

R5: R5 properly identifies a performance-based criteria.

R6: R6 is properly worded and is performance-based.

R7: R7 requires the entity to review and update its seasonal ERA process "if needed". This puts a burden on the entity to prove when and updated is warranted. During enforcement, if a document is not updated regularly, the auditor will assume it is not being maintained properly. Entities will have to explain why there was no need to update the documentation. Auditors will default to looking for errata errors in the documentation. This leads to zero defect compliance practices that NERC has been trying to distance itself from with better written standards.

R8: In R8 the entities are asked to "...provide [their] seasonal ERA process, Scenarios or methods, and Operating Plans(s)... to the RC at least once every 24 Calendar Months, on a mutually agreed schedule." R1 and R2 require the BAs to develop a seasonal ERA process and Scenarios, and R3 requires the entity to create Operating Plans based on the ERA process. The Operating Plans are done each season identified by the individual BA. This makes the product from R3 only relevant to the season it is looking at. Requiring entities to provide the "...Scenarios or methods, and Operating Plans..." at least once every 24 calendar months is confusing and provides no benefit since the Scenarios and operating plans will be stale. The submission of the ERA process under R1 makes sense, since it is supposedly reviewed and updated in that period; but providing Scenarios, methods and Operating Plans every 24 months is of no use. It is recommended that ONLY the updated ERA process be submitted to the RC every 24 calendar months. Seasonal assessment results should be provided no later than 30 days prior to the start of the season, and operating plans should not be included.

The ERA process submission to the RC should require resubmission after any revision is made to the process. The current proposal allows an entity to submit its plan to the RC, then if they update their document, it doesn't have to be resubmitted until the next 24-month submittal. Other NERC Standards require entities to submit revised processes within 30 or 60 days of any update.

R9: The lead in sentence of R9 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider: "The Reliability Coordinator, within 60 days of receipt of the information identified in Requirement R9, shall:"

R10: The lead in sentence of R10 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider: "The Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit updated information within the schedule specified by the Reliability Coordinator.

R11: It is not clear why the Drafting Team elected to put a follow-on requirement to R1 so low in the list of requirements. R11 should be combined with R2 or R3 as a performance requirement the R1 requirement. Alternatively, R11 could be moved up to R3, and renumbering the current requirements R3 through R13.

R12: R12 is not needed, since BAL-007 requirements require short-term assessments and operating plans, which would address and override any plans made over 6 months out in a seasonal ERA.

R13: R13 is confusing, since it is requiring 7 days of notice of the implementation of an operating plan that would most likely be implemented in, or very close to, real-time. Fundamentally, operation plans from seasonal studies will be overridden by BAL-007 operating plans in the near-term.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

There is an incomplete framework for R4. Need a more defined way of obtaining data from the Generator Operators as described in our response to Question 13.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI does not oppose the changes made to Requirements R4, R5, R6, R7, R8, R10, R11 and R12 but we do have concerns with the proposed changes to R2, R3, R9 and R13.

Requirement R2 Concerns: EEI does not support language contained in subpart 2.3 because the BA should have sole authority to determine what constitutes "other scenarios with a credible risk". We additionally do not agree that it is necessary to include "or historical" within subpart 2.3 because the BA already has awareness of historical risks within their BA region and those risks factor into their assessment of what is a credible risk. To address our concerns, we offer the following changes to Requirement R2, subpart 2.3 (in boldface):

2.3. Other Scenarios with a credible risk of occurring **as determined by the BA**.

Requirement R3 Concerns: While EEI appreciates the intent of the proposed language to minimize forecasted Energy Emergencies, the proposed language provides no clarity regarding this process. To address this concern, including language that makes it clear that the BA has sole discretion regarding when it is necessary to notify the RC of forecasted Energy Emergencies is needed. Such discretion would rightly provide due weight to the technical expertise of the BA allowing that functional entity to recognize when there is an imminent risk to the reliability of the BES and when it would be necessary to issue a notification under this Requirement.

R3: Each Balancing Authority shall document and maintain one or more Operating Plan(s) as identified in the seasonal ERA **that include** provisions for notifying the Reliability Coordinator of **a** forecasted Energy Emergency and the Operating Plan(s), **when deemed necessary**. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Requirement R9 Concerns: EEI notes that Requirement R9 cites certain RC actions related to Requirement R8. Requirement R8 is an administrative Requirement that simply obligates the BA to supply their seasonal ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. Under Requirement R9 the RC is obligated to review the R8 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days and therefore is administrative activity and should not have a VRF higher than Low.

Requirement R13 Concerns: EEI does not support the proposed language of Requirement R13 because of the following concerns:

1. For a seasonal forecasted Energy Emergency, obligating the RC to respond within 7 days when a seasonal forecasted Energy Emergency is unlikely to ever represent an imminent emergency is unjustified. EEI suggests 30 days as a more appropriate and reasonable timeframe.

2. Not all forecasted seasonal EEA need to be circulated. The RC needs to review the forecasted EEA and determine if it is credible. If not, they should return it to the BA with questions before circulating it to other BAs within their footprint and neighboring RCs.

3. EEI does not support a medium VRF for forecasted seasonal EEA given a seasonal Forecasted EEA does not have the same level of urgency as a seasonal forecasted EEA.

R13. Each Reliability Coordinator, **who receives notification of a forecasted seasonal Energy Emergency, pursuant to Requirement R3 that includes an implemented Operating Plan pursuant to Requirement R8 and evaluated as credible by the Reliability Coordinator; shall** within **thirty (30)** calendar days of receiving **the** notification notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of the forecasted condition(s) and the Balancing Authority's Operating Plan(s). **If the RC determines the forecasted seasonal Energy Emergency is not credible or they have questions, they shall transmit their concerns to the responsible BA for further review & discussion.** [Violation Risk Factor: **Low**] [Time Horizon: Operations Planning]

Likes 0	
Dislikes 0	

Response

Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6

Answer	No
Document Name	

Comment

Puget Sound Energy agrees with WPP's response to this question, shown below.

R2: In general, R2 is vague and ambiguous. It amounts to a fill-in-the-blank standard which puts entities in a position where they will be held accountable for their own practices. This incentivizes companies to meet minimum criteria to not risk potential non-compliance. Entities exceeding expectations will be rewarded with additional compliance risk. R2 has no performance measurements associated and no minimum level of performance. NERC Standards should be performance based, not administrative. Documentation of Scenarios, methods, and the rationales will result in subjective enforcement and issues related to quality. Entities will be exposed to compliance risk for administrative mistakes and errata errors, rather than poor performance that can put the BES in risk. The drafting team is encouraged to consider what a minimal acceptable performance should be for seasonal ERAs.

The Drafting Team utilizes the term "credible" several times. Credible is a subjective term and what is credible to one entity (or auditor), may not be credible to another. This leaves the entity in a very difficult situation when being audited against R2.

R3: R3 requires the BA to document and maintain one or more Operating Plans to minimize forecasted Energy Emergencies identified through the ERA, but they are not required to implement plans when an Energy Emergency is identified. BAs maintain Operating Plans under TOP-002, and it is not clear if these can be the same or different Operating Plans identified in TOP-002. TOP-002 deals with next-day operations and it is confusing if the proposed BAL-008 Operating Plans are superseded by next day or real-time Operation Plans.

R3 uses the phrase "...minimize forecasted Energy Emergencies..." the term "minimize" is subjective and not measurable. Though the intent of the drafting team seems clear, enforcement it will be up to the auditor to determine if the entity is effectively minimizing identified Energy Emergencies.

The measures in both R2 and R3 give little guidance to an entity, or the auditor, as to what evidence is sufficient. The two requirements are administrative and require documents for compliance, but do not set a minimum criterion for performance. This encourages minimal compliance, and not acceptable levels of performance.

R4: R4 properly identifies a performance-based criteria.

R5: R5 properly identifies a performance-based criteria.

R6: R6 is properly worded and is performance-based.

R7 requires the entity to review and update its seasonal ERA process "if needed". This puts a burden on the entity to prove when and updated is warranted. During enforcement, if a document is not updated regularly, the auditor will assume it is not being maintained properly. Entities will have to explain why there was no need to update the documentation. Auditors will default to looking for errata errors in the documentation. This leads to zero defect compliance practices that NERC has been trying to distance itself from with better written standards.

R8: In R8 the entities are asked to "...provide [their] seasonal ERA process, Scenarios or methods, and Operating Plans(s)... to the RC at least once every 24 Calendar Months, on a mutually agreed schedule." R1 and R2 require the BAs to develop a seasonal ERA process and Scenarios, and R3 requires the entity to create Operating Plans based on the ERA process. The Operating Plans are done each season identified by the individual BA. This makes the product from R3 only relevant to the season it is looking at. Requiring entities to provide the "...Scenarios or methods, and Operating Plans..." at least once every 24 calendar months is confusing and provides no benefit since the Scenarios and operating plans will be stale. The submission of the ERA process under R1 makes sense, since it is supposedly reviewed and updated in that period; but providing Scenarios, methods and Operating Plans every 24 months is of no use. It is recommended that ONLY the updated ERA process be submitted to the RC every 24 calendar months. Seasonal assessment results should be provided no later than 30 days prior to the start of the season, and operating plans should not be included.

The ERA process submission to the RC should require resubmission after any revision is made to the process. The current proposal allows an entity to submit its plan to the RC, then if they update their document, it doesn't have to be resubmitted until the next 24-month submittal. Other NERC Standards require entities to submit revised processes within 30 or 60 days of any update.

R9: The lead in sentence of R9 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider: "The Reliability Coordinator, within 60 days of receipt of the information identified in Requirement R9, shall:"

R10: The lead in sentence of R10 is written passively and should be revised to follow good standard writing structure. The responsible entity should be stated first, then the actions or requirement should follow. The Drafting Team should consider: "The Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit updated information within the schedule specified by the Reliability Coordinator."

R11: It is not clear why the Drafting Team elected to put a follow-on requirement to R1 so low in the list of requirements. R11 should be combined with R2 or R3 as a performance requirement the R1 requirement. Alternatively, R11 could be moved up to R3, and renumbering the current requirements R3 through R13.

R12: R12 is not needed, since BAL-007 requirements require short-term assessments and operating plans, which would address and override any plans made over 6 months out in a seasonal ERA.

R13: R13 is confusing, since it is requiring 7 days of notice of the implementation of an operating plan that would most likely be implemented in, or very close to, real-time. Fundamentally, operation plans from seasonal studies will be overridden by BAL-007 operating plans in the near-term.

Likes 0	
Dislikes 0	

Response

Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

Seminole agrees with FRCC's comments below

R2:
The FRCC believes that R2 is too vague, especially the "Credible" term, will in turn, promote BAs to create their own standard to be audited against. This situation will have the opposite effect of what is intended. The focus will be on compliance and not on actual Resource Adequacy. Also, the BAs will have to account for compliance risks due to administrative errors, not for inadequate performance that creates a real risk to the BES. The FRCC suggests the drafting team define what the minimal acceptable performance level should be for these assessments and define what "Credible" is intended to address.
R3:
The FRCC acknowledges the intent of the proposed language to minimize forecasted Energy Emergencies, but still has concerns that the proposed language provides no improved clarity regarding this process. The FRCC suggests including language that makes it clear that the BA has sole discretion regarding when it is necessary to notify the RC of forecasted Energy Emergencies. Such discretion would rightly provide due weight to the technical expertise of the BA allowing that functional entity to recognize when there is an imminent risk to the reliability of the BES and when it would be necessary to issue a notification under this Requirement.

R9:
The FRCC agrees with and supports the Edison Electric Institute (EEI) severity risk comments on R9:
Requirement R9 Concerns: EEI notes that Requirement R9 cites certain RC actions related to Requirement R8. Requirement R8 is an administrative Requirement that simply obligates the BA to supply their seasonal ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. Under Requirement R9 the RC is obligated to review the R8 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days and therefore is administrative activity and should not have a VRF higher than Low.
R13:
The FRCC has the following concerns with the proposed language of Requirement R13:
1. It is extremely unlikely that there would ever be a scenario where, due to a forecasted Energy Emergency from a seasonal forecast where it would be necessary for the RC to respond within 7 days to mitigate the imminent emergency. The FRCC suggests 30 days as a more realistic and appropriate timeframe.
2. The FRCC believes that the seasonal ERAs should be reviewed and verified to be accurate. Should the RC not agree with the results of the seasonal ERA, it should be returned to the respective BA for revision. The RC should only publish and/or communicate the results to the BAs within its reliability area and adjacent Reliability Coordinators when this review and approval is complete.
3. The FRCC agrees with and supports EEI's severity risk comments on R13.

Likes 0	
Dislikes 0	
Response	
LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	

Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

APS agrees with some of the proposed BAL-008 requirements but not all.

Regarding R4, as it relates to Balancing Authority data specifications, how do entities obligate third-party merchants that may not be required to comply with NERC Standards to provide data to Balancing Authorities?

Regarding R10, what is the metric for reliability risks identified by the RC? If Balancing Authorities are defining the risks or conditions within each seasonal period, R10 appears to require Balancing Authorities to comply with the reliability risks identified by its Reliability Coordinator which are not explicitly defined in the requirement. More definition is warranted on how a Reliability Coordinator defines reliability risk and when. If it is intended to be predefined from other standards, it is recommended to explicitly call out the energy reliability risks within this requirement.

Regarding R12, APS is of the opinion that R12 reaches beyond the seasonal time period scope. If Balancing Authorities are provided the flexibility to define the circumstances, risks, or conditions within each seasonal period, it appears the forecasted EEA1 circumstances as defined in EOP-011 Attachment 1 Section B identified in R12 must be included in R1 as it is not included or defined. APS is of the opinion that R12 is duplicative of efforts already performed within EOP-011 R2.

Regarding R13, APS agrees with the following EEI comments:

Requirement R13 Concerns: EEI does not support the proposed language of Requirement R13 because of the following concerns:

1. For a seasonal forecasted Energy Emergency, obligating the RC to respond within 7 days when a seasonal forecasted Energy Emergency is unlikely to ever represent an imminent emergency is unjustified. EEI suggests 30 days as a more appropriate and reasonable timeframe.

Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	No
Document Name	

Comment	
(footnote: SPP is a party to these comments however does not support the references about duplication with EOP-011 requirements. SPP supports the need for reporting ERA results in BAL-007 however there is lack of clarity between the BAL-007 and EOP-011 obligations.) The framework in R4 – R6 is incomplete. Specifically, it also needs to address data acquisition from Generator Operators as described in the SRC's response to Question 13. Requirements R3, R7 – R10, and R12 – R13 are unnecessarily duplicative of EOP-011, IRO-014, and TOP-002 in same manner as BAL-007 R3 - R7, R9, and R10, as discussed in more detail in the SRC's responses to questions 3, 5, and 8. These requirements should either be removed or, if retained, modified consistent with the SRC's responses to questions 3, 5, and 8. The SRC particularly requests that the SDT clarify in Part 9.1 that coordination with other BAs is specific to BAs within the RC Area and remove the unnecessary reference to ERA information, and proposes that Part 9.1 be revised to read as follows: R9.1. Review each submittal for coordination with other Balancing Authorities in its Reliability Coordinator Area to avoid risks to Wide Area reliability; and	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	No
Document Name	
Comment	
R2: The FRCC believes that R2 is too vague, especially the "Credible" term, will in turn, promote BAs to create their own standard to be audited against. This situation will have the opposite effect of	

what is intended. The focus will be on compliance and not on actual Resource Adequacy. Also, the BAs will have to account for compliance risks due to administrative errors, not for inadequate performance that creates a real risk to the BES. The FRCC suggests the drafting team define what the minimal acceptable performance level should be for these assessments and define what “Credible” is intended to address.

R3:

The FRCC acknowledges the intent of the proposed language to minimize forecasted Energy Emergencies, but still has concerns that the proposed language provides no improved clarity regarding this process. The FRCC suggests including language that makes it clear that the BA has **sole discretion** regarding when it is necessary to notify the RC of forecasted Energy Emergencies. Such discretion would rightly provide due weight to the technical expertise of the BA allowing that functional entity to recognize when there is an imminent risk to the reliability of the BES and when it would be necessary to issue a notification under this Requirement.

R9:

The FRCC agrees with and supports the Edison Electric Institute (EEI) severity risk comments on R9: **Requirement R9 Concerns**: EEI notes that Requirement R9 cites certain RC actions related to Requirement R8. Requirement R8 is an administrative Requirement that simply obligates the BA to supply their seasonal ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. Under Requirement R9 the RC is obligated to review the R8 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days and therefore is administrative activity and should not have a VRF higher than Low.

R13:

The FRCC has the following concerns with the proposed language of Requirement R13:

1. It is extremely unlikely that there would ever be a scenario where, due to a forecasted Energy Emergency from a seasonal forecast where it would be necessary for the RC to respond within 7 days to mitigate the imminent emergency. The FRCC suggests 30 days as a more realistic and appropriate timeframe.
2. The FRCC believes that the seasonal ERAs should be reviewed and verified to be accurate. Should the RC not agree with the results of the seasonal ERA, it should be returned to the respective BA for revision. The RC should only publish and/or communicate the results to the BAs within its reliability area and adjacent Reliability Coordinators when this review and approval is complete.
3. The FRCC agrees with and supports EEI’s severity risk comments on R13.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Sacramento Municipal Utility District - 1,3,4,5,6 - WECC, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

SMUD and BANC agree with the comments submitted by the Western Power Pool.

Likes 0	

Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

R4 Proposed revision - Replace "Resource Planners" with "Resource Planner(s)" to align with R5 and proposed R6 revision below. R6 Proposed revision - "Resource Planner(s) receiving a data specification from the Balancing Authority per Requirement R5 shall satisfy the obligations of the documented specifications using:

6.1 A mutually agreeable format;

6.2 A mutually agreeable process for resolving data conflicts; and

6.3 A mutually agreeable data security protocol."

This makes it clear there may be more than one resource planner (as in R5) and also clarifies that the Balancing Authority and Resource Planner(s) must mutually agree on the requirements in 6.1-6.3.

In addition, Resource Planners may not be the appropriate responsible entity for seasonal ERAs for all entities. SRP appreciates the flexibility of creating an operating plan with timelines and scenarios that are appropriate for its BA, more guidance could be helpful to ensure an Operating Plan and associated evidence meets the expectations of the standard.

Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	

Madison Gas and Electric supports the comments of the MRO NSRF.

Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	
Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No

Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	

Recommend changing R2.1 to “Forecasted Demand profiles”	
Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
The terms ‘credible situation’, ‘credible energy supply Contingency,’ and ‘credible fuel supply Contingency’ are new to this Standard. Consider including clarifications of the meanings of these terms in the Technical Rationale.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
SPP requests the removal of the “on mutually agreed upon schedule” from R8 leaving a set time requirement of at least once every 24 calendar months. Requiring a mutually agreed upon schedule for each entity is administratively burdensome for the documented evidence.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	

MISO answers "No." (We had difficulty entering our comments into the SBS.)

The framework in R4 – R6 is incomplete. Specifically, it also needs to address data acquisition from Generator Operators as described in the SRC's response to Question 13.

Requirements R3, R7 – R10, and R12 – R13 are unnecessarily duplicative of EOP-011, IRO-014, and TOP-002 in same manner as BAL-007 R3 - R7, R9, and R10, as discussed in more detail in our response to questions 3, 5, and 8. These requirements should either be removed or, if retained, modified consistent with the SRC's responses to questions 3, 5, and 8.

We request the SDT clarify in Part 9.1 that coordination with other BAs is specific to BAs within the RC Area and remove the unnecessary reference to ERA information, and proposes that Part 9.1 be revised to read as follows:

9.1. Review each submittal for coordination with other Balancing Authorities in its Reliability Coordinator Area to avoid risks to Wide Area reliability; and

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

It appears BAL-008-1 Requirement R13 should reference Requirement 12, which refers to the implementation of an Operating Plan(s) based on the circumstances, instead of Requirement R8, which is the periodic submission of BA's documented seasonal ERA process, Scenarios or methods,

The Requirement R13 Violation Severity Levels table language correctly refers to Requirement R12.

Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1	
Answer	

Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies LLC - 5	
Answer	
Document Name	
Comment	
R2 appears to allow the BA to account for EITHER "Forecasted or assumed Demand profiles" OR the disruptions to supply listed under 2.2. Given that most if not all recent reliability events have been caused by a combination of a spike in demand coincident with a failure of generation supply, R2 should require the BA to model a scenario in which both demand is high and generation supply experiences outages. The modeling of generation supply outages should be based on the most severe historical supply disruptions the BA has experienced, which for most BAs is a correlated loss of gas generation.	
Likes 0	
Dislikes 0	
Response	

12. BAL-008-1 Seasonal ERAs: The SDT drafted the BAL-008-1 implementation plan to allow for 18 months for Requirements R1 through R6 and 24 months for Requirements R7- R13 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	No
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	No
Document Name	
Comment	
SPP has concerns about implementing at the same time as BAL-007 and would request a staggered implementation plan between the BAL-007 and BAL-008 standards.	
Likes 0	
Dislikes 0	
Response	

Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	No
Document Name	
Comment	
The FRCC does not support an 18-month implementation period for Requirements R1 through R3. The resulting burden of work associated with changing internal processes, developing credible scenarios and operating plans will be very time consuming. The FRCC recommends an implementation period of **at least** 24 months for all requirements.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	No
Document Name	
Comment	
As noted in the SRC's response to Question 13, the plan is incomplete without a commensurate update and Implementation Plan for TOP-003 that takes place prior to the implementation timeline for BAL-008. Additionally, as noted in the SRC's response to question 6, the resources and expertise needed to implement BAL-008 (particularly if ERAs are going to be automated) may already be engaged on other long-term projects that will need to be completed before being available to address BAL-008 implementation. Consequently, while the SRC appreciates the updates to the implementation plan, the SRC requests that the implementation plan be further revised to allow 36 months for the implementation of all Requirements.	
Likes 0	

Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	
APS agrees with the following EEI comments: EEI does not support 18 months for Requirements R1 through R3. The work associated with changing internal processes, developing credible scenarios and operating plans will be time consuming. To address this concern, the implementation plan should allow 24 months for all of the requirements.	
Likes 0	
Dislikes 0	
Response	
LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	
Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seminole agrees with FRCC's comments below	

The FRCC does not support an 18-month implementation period for Requirements R1 through R3. The resulting burden of work associated with changing internal processes, developing credible scenarios and operating plans will be very time consuming. The FRCC recommends an implementation period of at least 24 months for all requirements.	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
Puget Sound Energy agrees with WPP's response to this question, shown below. *The timeline proposed states that the entities have 18 months to comply to R1 through R6. The problem is that under R1 the seasonal ERA process must be sent to the RC for review. If the RC is sent the ERA process for review at the end of the 18-month period, the RC then has 60 days to review, and can send the process back to the entity for correction. The entity can take another 60 days to correct and resubmit the process to the RC. Finally, the RC has an additional 60 days to review and accept the modified process. Once the plan is accepted by the RC, the entity can begin to meet R2 and R6 compliance. Stepping through this process results in a significant delay in implementation of R2 through R6. If the process is followed as the implementation plan suggests, entities run the risk of creating the ERA process, developing Scenarios and operating plans,that will all have to be redone due to a problem that the RC finds with their ERA process.* *The Drafting Team should consider adjusting the implementation of BAL-008. Perhaps it is more appropriate to require implementation of R1 by 12 months after the effective date of the standard, The other requirements can be implemented by 18 months after the effective date, with full implementation of the standards reached within 24 months after the effective date.*	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support 18 months for Requirements R1 through R3. The work associated with changing internal processes, developing credible scenarios and operating plans will be time consuming. To address this concern, the implementation plan should allow 24 months for all of the requirements.	
Likes 0	

Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment

As noted in our response to Question 13, the plan is incomplete without a commensurate update and Implementation Plan for TOP-003 that takes place prior to the implementation timeline for BAL-008.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	

Comment

USV supports the comments provided by MISO regarding the number of resources required to address BAL-008 implementation.

Likes 0	
Dislikes 0	

Response

Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	

Comment

PSE agrees with WPP's response to this question, shown below.

The timeline proposed states that the entities have 18 months to comply to R1 through R6. The problem is that under R1 the seasonal ERA process must be sent to the RC for review. If the RC is sent the ERA process for review at the end of the 18-month period, the RC then has 60 days to review, and can send the process back to the entity for correction. The entity can take another 60 days to correct and resubmit the process to the RC. Finally, the RC has an additional 60 days to review and accept the modified process. Once the plan is accepted by the RC, the entity can begin to meet R2 and R6 compliance. Stepping through this process results in a significant delay in implementation of R2 through R6. If the process is followed as the *implementation plan suggests, entities run the risk of creating the ERA process, developing Scenarios and operating plans, that will all have to be redone due to a problem that the RC finds with their ERA process.*

The Drafting Team should consider adjusting the implementation of BAL-008. Perhaps it is more appropriate to require implementation of R1 by 12 months after the effective date of the standard, The other requirements can be implemented by 18 months after the effective date, with full implementation of the standards reached within 24 months after the effective date.

Likes 0	
Dislikes 0	

Response

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	No
Document Name	

Comment

Supporting EEI comments.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power endorses the comments provided by the Western Power Pool.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 12	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
The plan is incomplete without an update and implementation Plan for TOP-003 that takes place prior to the implementation timeline for BAL-008.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren supports MISO's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	No
Document Name	
Comment	
WECC believes clarity is needed as the Implementation Plan as it states that BAL-008-1 will be “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.” Then, for phased-in Compliance Date there is language for R1, R2, R3, R4, R5 and R6 that states entities have 18 months after the effective date of the Standard in essence allowing 36 months after the effective date for entities to be compliant. Other Requirements also have the “following the effective date” with 24 month additional time period. Please draw a timeline of expected implementation so that all parties, including FERC, are in clear understanding of when Requirements actually become auditable and enforceable. As is, the first 18 months, as written, is not an effective time period as nothing changes in terms of efforts. Drawing a timeline associated with effective implementation dates should be part of the Standards process.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

The timeline proposed states that the entities have 18 months to comply to R1 through R6. The problem is that under R1 the seasonal ERA process must be sent to the RC for review. If the RC is sent the ERA process for review at the end of the 18-month period, the RC then has 60 days to review, and can send the process back to the entity for correction. The entity can take another 60 days to correct and resubmit the process to the RC. Finally, the RC has an additional 60 days to review and accept the modified process. Once the plan is accepted by the RC, the entity can begin to meet R2 and R6 compliance. Stepping through this process results in a significant delay in implementation of R2 through R6. If the process is followed as the implementation plan suggests, entities run the risk of creating the ERA process, developing Scenarios and operating plans, that will all have to be redone due to a problem that the RC finds with their ERA process.

The Drafting Team should consider adjusting the implementation of BAL-008. Perhaps it is more appropriate to require implementation of R1 by 12 months after the effective date of the standard, The other requirements can be implemented by 18 months after the effective date, with full implementation of the standards reached within 24 months after the effective date.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment

TEPC agrees with EEI's comments - EEI does not support 18 months for Requirements R1 through R3. The work associated with changing internal processes, developing credible scenarios and operating plans will be time consuming. To address this concern, the implementation plan should allow for 24 months for all of the requirements.

Likes 0	
Dislikes 0	

Response

Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group

Answer	No
Document Name	

Comment

CHPD supports WPP’s response. CHPD, suggests another acceptable implementation timeline is to have a version initially submitted by the effective date, and an approved version within six months of implementation.

Likes 0	
Dislikes 0	

Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA's full response in question 15.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI's comments. EEI does not support 18 months for Requirements R1 through R3. The work associated with changing internal processes, developing credible scenarios and operating plans will be time consuming. To address this concern, the implementation plan should allow 24 months for all of the requirements.	
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 a 24-month implementation timeline for all BAL-008-1 requirements.	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	No
Document Name	
Comment	
For the reasons outlined in our response to the Questions above, BC Hydro is unable to support the proposed implementation plan at this time.	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group

Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
As noted in our response to Question 13, the plan is incomplete without a commensurate update and Implementation Plan for TOP-003 that takes place prior to the implementation timeline for BAL-008.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	

Comment	
Duke Energy supports proposed EEI language modifications for Question 12.	
Likes 0	
Dislikes 0	
Response	
Reed Adam - Seattle City Light - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The timeline proposed states that the entities have 18 months to comply to R1 through R6. The problem is that under R1 the seasonal ERA process must be sent to the RC for review. If the RC is sent the ERA process for review at the end of the 18-month period, the RC then has 60 days to review, and can send the process back to the entity for correction. The entity can take another 60 days to correct and resubmit the process to the RC. Finally, the RC has an additional 60 days to review and accept the modified process. Once the plan is accepted by the RC, the entity can begin to meet R2 and R6 compliance. Stepping through this process results in a significant delay in implementation of R2 through R6. If the process is followed as the implementation plan suggests, entities run the risk of creating the ERA process, developing Scenarios and operating plans, that will all have to be redone due to a problem that the RC finds with their ERA process. The Drafting Team should consider adjusting the implementation of BAL-008. Perhaps it is more appropriate to require implementation of R1 by 12 months after the effective date of the standard, The other requirements can be implemented by 18 months after the effective date, with full implementation of the standards reached within 24 months after the effective date.	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
SCL is in support and alignmnet with WPP's & Idaho's submitted comments.	
Likes 0	
Dislikes 0	
Response	

Daren Brubaker - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
I agree with the comments provided by Western Power Pool.	
Likes 0	
Dislikes 0	
Response	

Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seattle City Light agrees with WPP Submitted Comment.	
Likes 0	
Dislikes 0	
Response	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	

Idaho Power agrees with WPP's response to this question, shown below.

The timeline proposed states that the entities have 18 months to comply to R1 through R6. The problem is that under R1 the seasonal ERA process must be sent to the RC for review. If the RC is sent the ERA process for review at the end of the 18-month period, the RC then has 60 days to review, and can send the process back to the entity for correction. The entity can take another 60 days to correct and resubmit the process to the RC. Finally, the RC has an additional 60 days to review and accept the modified process. Once the plan is accepted by the RC, the entity can begin to meet R2 and R6 compliance. Stepping through this process results in a significant delay in implementation of R2 through R6. If the process is followed as the implementation plan suggests, entities run the risk of creating the ERA process, developing Scenarios and operating plans, that will all have to be redone due to a problem that the RC finds with their ERA process.

The Drafting Team should consider adjusting the implementation of BAL-008. Perhaps it is more appropriate to require implementation of R1 by 12 months after the effective date of the standard, The other requirements can be implemented by 18 months after the effective date, with full implementation of the standards reached within 24 months after the effective date.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
For the same reason in BAL-007 R4, ISO-NE recommends moving BAL-008 R7 to the 18 month effective date. ISO-NE would support a change to 36 months Implementation timeframe for all requirements.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	

Kimberly Turco on behalf of Constellation Segments 5 and 6

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 EEI that 24 months is a more reasonable implementation timeframe.	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mark Flanary - Midwest Reliability Organization - 10	
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	
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	
Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 5,6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	
Document Name	
Comment	
MISO answers "No." (We had difficulty entering our comments into the SBS.) As noted in MISO's response to Question 13, the plan is incomplete without a commensurate update and Implementation Plan for TOP-003 that takes place prior to the implementation timeline for BAL-008. Additionally, as noted in MISO's response to question 6, the resources and expertise needed to implement BAL-008 (particularly if ERAs are going to be automated) may already be engaged on other long-term projects that will need to be completed before being available to address BAL-008 implementation. Consequently, while MISO appreciates the updates to the implementation plan, MISO requests that the implementation plan be further revised to allow 36 months for the implementation of all Requirements.	
Likes 0	

Dislikes 0	
Response	

13. BAL-008-1 Seasonal ERAs: The SDT believes that fuel data information needed to address BAL-008-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

Idaho Power agrees with WPP's response to this question, shown below.

The BAs can expand their Operational Reliability Data requests through TOP-003, however this could further slow the implementation of proposed standard BAL-008 due to the time needed to notify the entities, and for them to turn the information around back to the BA before the ERA process can begin.

Fuel information from entities not listed in TOP-003 can be problematic. This includes natural gas suppliers, and entities not registered as users, owners, or operators of the BES, not under the purview of the BA or who have contracts specifically limiting access to market sensitive information.

Likes 0	
Dislikes 0	

Response

Chris Shultz - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

Seattle City Light agrees with WPP Submitted Comment.

Likes 0	
Dislikes 0	

Response

Daren Brubaker - Seattle City Light - 1,3,4,5,6

Answer	No
Document Name	

Comment

I agree with the comments provided by Western Power Pool.	
Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
SCL is in support and alignmnet with WPP's & Idaho's submitted comments.	
Likes 0	
Dislikes 0	
Response	
Reed Adam - Seattle City Light - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The BAs can expand their Operational Reliability Data requests through TOP-003, however this could further slow the implementation of proposed standard BAL-008 due to the time needed to notify the entities, and for them to turn the information around back to the BA before the ERA process can begin. Fuel information from entities not listed in TOP-003 can be problematic. This includes natural gas suppliers, and entities not registered as users, owners, or operators of the BES, not under the purview of the BA or who have contracts specifically limiting access to market sensitive information.	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	
Answer	No
Document Name	
Comment	

Past experience clearly indicates a change to TOP-003 is necessary to enable BAs to collect the necessary information regarding "fuel supply and inventory concerns" year-round (to the extent this information is even available from NERC-registered entities).

- TOP-003-5 does not extend to information needed to perform ERAs. Requirement R1 is limited to "Operational Planning Analyses, Real-time monitoring, and Real-time Assessments" (items required in support of TOP-002 and TOP-001 only). When viewed in conjunction with R2, a case could be made that TOP-003-5, R2 is likewise limited to information needed for TOP-002 and TOP-001 only.
- In addition, TOP-003 was recently updated to specifically address information regarding "fuel supply and inventory concerns" under cold weather conditions pursuant to Project 2019-06 and further expanded under Project 2021-07 (*See* TOP-003-5 and TOP-0003-6.1, Part 2.3.1.2). This indicates that TOP-003 does not address fuel-related information that would be needed to implement BAL-008.

The modifications to TOP-003 to mandate the provision of "fuel supply and inventory concerns," only require this information to be provided during local forecasted Cold Weather conditions. Therefore, a change to TOP-003 would be required to mandate the provision of "fuel supply and inventory concerns" year-round if BAL-008 persists in its current form.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

Past practice indicates a change to TOP-003 is necessary to collect "fuel supply and inventory concerns" information year-round.

· TOP-003-5 is unclear as to what information must be provided by entities in support of ERAs. Requirement R1 is limited to "Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." (Items required in support of TOP-002 and TOP-001 only). When viewed in conjunction with R2, a case could be made that TOP-003, R2 likewise is limited in support of TOP-002 and TOP-001 only. TOP-003 does not include the collection of data necessary to perform seasonal ERAs (more akin to planning studies).

· In addition, if fuel data needed by BAs to address BAL-008 is covered under TOP-003, why then was TOP-003 updated to specifically require information regarding "fuel supply and inventory concerns" under cold weather conditions pursuant to Project 2019-06 and further expanded under Project 2021-07? (See TOP-003-5 and TOP-0003-6.1, Part 2.3.1.2)

Both Cold Weather projects modified TOP-003 to mandate the provision of "fuel supply and inventory concerns," so that it only applies during local forecasted Cold Weather conditions. Therefore, **a change to TOP-003 would be required to mandate the provision of "fuel supply and inventory concerns" year-round.**

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5	
Answer	No
Document Name	
Comment	
TOP-003 is covers data needs specific to OPA, RTA and RTM and may not provide sufficient authority for the BA to request specific data necessary for ERAs. BC Hydro suggests that a revision to the current TOP-003 or a new ERA-specific Requirement would be necessary prior to implementing BAL-008-1.	
Likes 0	
Dislikes 0	
Response	

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
This could potentially put the BA at odds with the GO and GOP as to the applicability of TOP-003. TOP-003 today is only used for data in the near real time horizon and the GO or GOP could argue that the data required for these studies is beyond the scope of TOP-003. While the BAs could attempt to use TOP-003 for this data acquisition, it would be better to include the requirement to supply the data needed in the standard.	
Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Please see BPA's full response in question 15.	
Likes 0	
Dislikes 0	
Response	

Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	
CHPD supports WPP's response	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
The BAs can expand their Operational Reliability Data requests through TOP-003, however this could further slow the implementation of proposed standard BAL-008 due to the time needed to notify the entities, and for them to turn the information around back to the BA before the ERA process can begin. Fuel information from entities not listed in TOP-003 can be problematic. This includes natural gas suppliers, and entities not registered as users, owners, or operators of the BES, not under the purview of the BA or who have contracts specifically limiting access to market sensitive information.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren supports MISO's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	

Answer	No
Document Name	
Comment	

Current practice clearly indicates that a change to TOP-003 is necessary to collect “fuel supply and inventory concerns” information year-round.

Likes 0	
Dislikes 0	
Response	

Hayden Maples - Evergy - 1,3,5,6 - MRO

Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 13

Likes 0	
Dislikes 0	
Response	

Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power

Answer	No
Document Name	
Comment	

Tacoma Power endorses the comments provided by the Western Power Pool.

Likes 0	
Dislikes 0	
Response	

Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper

Answer	No
Document Name	

Comment	
It will likely be a problem getting fuel information from entities that are not Registered Entities as they are not required to comply with the NERC Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
PSE agrees with WPP's response to this question, shown below. *The BAs can expand their Operational Reliability Data requests through TOP-003, however this could further slow the implementation of proposed standard BAL-008 due to the time needed to notify the entities, and for them to turn the information around back to the BA before the ERA process can begin.* *Fuel information from entities not listed in TOP-003 can be problematic. This includes natural gas suppliers, and entities not registered as users, owners, or operators of the BES, not under the purview of the BA or who have contracts specifically limiting access to market sensitive information.*	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	
Same response as question 7: TOP-003 enables the BA's to collect the necessary information, but it does not clearly specify the data necessary for ERAs, which are more akin to planning studies. USV supports the additional comments and suggestions provided by MISO.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

Past practice indicates a change to TOP-003 is necessary to collect "fuel supply and inventory concerns" information year-round.

{C}· TOP-003-5 is unclear as to what information must be provided by entities in support of ERAs. Requirement R1 is limited to "Operational Planning Analyses, Real-time monitoring, and Real-time Assessments." (Items required in support of TOP-002 and TOP-001 only). When viewed in conjunction with R2, a case could be made that TOP-003, R2 likewise is limited in support of TOP-002 and TOP-001 only. TOP-003 does not include the collection of data necessary to perform seasonal ERAs (more akin to planning studies).

{C}· In addition, if fuel data needed by BAs to address BAL-008 is covered under TOP-003, why then was TOP-003 updated to specifically require information regarding "fuel supply and inventory concerns" under cold weather conditions pursuant to Project 2019-06 and further expanded under Project 2021-07? (*See* **TOP-003-5** and **TOP-0003-6.1, Part 2.3.1.2**)

Both Cold Weather projects modified TOP-003 to mandate the provision of "fuel supply and inventory concerns," so that it only applies during local forecasted Cold Weather conditions. Therefore, **a change to TOP-003 would be required to mandate the provision of "fuel supply and inventory concerns" year-round.**

Likes 0	
Dislikes 0	
Response	

Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	

Puget Sound Energy agrees with WPP's response to this question, shown below.

The BAs can expand their Operational Reliability Data requests through TOP-003, however this could further slow the implementation of proposed standard BAL-008 due to the time needed to notify the entities, and for them to turn the information around back to the BA before the ERA process can begin.

Fuel information from entities not listed in TOP-003 can be problematic. This includes natural gas suppliers, and entities not registered as users, owners, or operators of the BES, not under the purview of the BA or who have contracts specifically limiting access to market sensitive information.

Likes 0	

Dislikes 0	

Response

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

TOP-003-5 does not cover the data requirements for ERA and we believe this could lead to issues with enforcing the standard. Two possible options for addressing this are 1) modify TOP-003-5 to include data requirements for ERA or 2) add a requirement to BAL-008-1 to address this data requirement.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance

Answer	No
Document Name	

Comment

Past experience clearly indicates a change to TOP-003 is necessary to enable BAs to collect the necessary information regarding “fuel supply and inventory concerns” year-round (to the extent this information is even available from NERC-registered entities).

• TOP-003-5 does not extend to information needed to perform ERAs. Requirement R1 is limited to “Operational Planning Analyses, Real-time monitoring, and Real-time Assessments” (items required in support of TOP-002 and TOP-001 only). When viewed in conjunction with R2, a case could be made that TOP-003-5, R2 is likewise limited to information needed for TOP-002 and TOP-001 only.

• In addition, TOP-003 was recently updated to specifically address information regarding “fuel supply and inventory concerns” under cold weather conditions pursuant to Project 2019-06 and further expanded under Project 2021-07 (See TOP-003-5 and TOP-0003-6.1, Part 2.3.1.2). This indicates that TOP-003 does not address fuel-related information that would be needed to implement BAL-008.

The modifications to TOP-003 to mandate the provision of “fuel supply and inventory concerns,” only require this information to be provided during local forecasted Cold Weather conditions. Therefore, a change to TOP-003 would be required to mandate the provision of “fuel supply and inventory concerns” year-round if BAL-008 persists in its current form.

Likes 0	

Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	

Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
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. - 3,4,5,6, Group Name WEC Energy Group	

Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the comments submitted by EEI and agrees that TOP-003 provides an appropriate mechanism for gathering needed fuel data in support of BAL-008-1.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Black Hills Corporation already has experience with TOP-003 and feels fuel data information can be achieved by adding it to our data specs.	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
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.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
TEPC does not agree, The new requirements will require additional staff and change in office configuration to add new desks.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	Yes
Document Name	
Comment	

WECC agrees with the concept that may already be in place for EOP-011 fuel data information required. However, the DT should consider using the same language as EOP-011. Additionally, TOP-003 may be considered limiting in that it is for data used in Operation Planning Analyses, Real-time monitoring, and Real-time Assessments. In this case (seasonal ERA) DT should provide language in the Technical Rationale to indicate a seasonal ERA maybe considered a form of OPA that would cover next day operations so that the definition of OPA is met (and alleviate anyone's concerns regarding use of TOP-003). May require an adjustment to TOP-003 to accommodate the seasonal aspect.

Likes 0	
Dislikes 0	

Response

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6

Answer	Yes
Document Name	

Comment

Supporting EEI comments.

Likes 0	
Dislikes 0	

Response

Keith Jonassen - ISO New England, Inc. - 2 - NPCC

Answer	Yes
Document Name	

Comment

Under TOP-003 R2 the "Each BA shall maintain a documented specification for the data necessary for it to perform its **analysis function** and real-time monitoring", with an Operations Planning time horizon.

ISO-NE believes that TOP-003 R2 satisfies the data collection requirements of BAL-008 and no additional data collection requirement wholly contained in BAL-008 or a modification of TOP-003 R2 is required.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	
EEI agrees that TOP-003 provides an appropriate mechanism for gathering needed fuel data in support of BAL-008-1.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Seminole agrees with FRCC's comments below The FRCC agrees that TOP-003 provides the mechanism needed by BAs to request fuel data information.	
Likes 0	
Dislikes 0	
Response	
LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	Yes
Document Name	
Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	Yes
Document Name	
Comment	
The FRCC agrees that TOP-003 provides the mechanism needed by BAs to request fuel data information.	
Likes 0	
Dislikes 0	
Response	
Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
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	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

14. BAL-008-1 Seasonal ERAs: The SDT proposes that the newly proposed BAL-008-1 meets the Standards Authorization Request 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.

George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	No
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	No
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	No
Document Name	
Comment	
The FRCC does not have and does not have any means to conduct an analysis or study determining that this proposal is cost-effective, and therefore does not support this statement. As previously noted in the BAL-007 comments, this proposed standard will most likely lead to an increase in staffing and administrative costs for all BAs and the RC function.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	No
Document Name	
Comment	

It is unclear why this activity cannot be accomplished under NERC's existing Reliability Assessment Committee (RAS) in a voluntary and collaborative fashion, as the RAS currently performs both Summer and Winter Reliability Assessments. In fact, seasonal ERAs could replace the existing deterministic Summer/Winter Assessments currently performed under this umbrella.

Consideration should also be given to how migrating this activity to a mandatory standard will harm the openness and sharing that is currently done both within and outside the group with interested stakeholders, including state regulators that have authority over matters of resource adequacy.

From an overall Standards Efficiency Review perspective, the latter 2/3 of BAL-008 (R5-R13) introduce unnecessary bureaucracy and new administrative requirements in comparison to the first 1/3 of BAL-008 (R1-R4), which seems to focus more on attempting to produce reliability results. Additionally, as detailed elsewhere in the SRC's comments, BAL-008 is currently substantively duplicative of EOP-011, TOP-002, and IRO-014 while simultaneously imposing additional administrative burdens that do not enhance system reliability. In addition, the standard presumes that BAs have access to fuel-related information that they do not possess and currently have no cost-effective method of obtaining. Removing the duplication and fully addressing the information access issues are necessary prerequisites to meeting the Standards Authorization Request in a cost-effective manner.

Likes 0	
Dislikes 0	
Response	

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

APS is in the opinion that implementation of BAL-008-1 would not meet the SAR in a cost effective manner as it creates an administrative burden for entities to either replace or revise existing processes that work well and may create a need for additional staffing to manage continuous seasonal ERAs.

Likes 0	
Dislikes 0	
Response	

LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)	
Answer	No
Document Name	

Comment	
FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seminole agrees with FRCC's comments below The FRCC does not have and does not have any means to conduct an analysis or study determining that this proposal is cost-effective, and therefore does not support this statement. As previously noted in the BAL-007 comments, this proposed standard will most likely lead to an increase in staffing and administrative costs for all BAs and the RC function.	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
: Puget Sound Energy agrees with WPP's response to this question, shown below. *We are not aware of any analysis or study determining that this proposal is cost-effective, and therefore do not support this statement. Since the proposed standard requires the BA to be responsible to meet the ERA studies, it will most likely require the hiring of specialized skill sets that are not currently on staff. This can have a significant cost impact to BAs when the resource adequacy analyses are shifted from the Resource Planners to the BAs. The cost/benefit has not been articulated by the Drafting Team, and when this questions was asked during a Drafting Team workshop, the Drafting Team admitted there was no analysis for cost effectiveness.*	

BAs, if given the opportunity, will try and pool their resources and create Emergency Energy Plans and form Resource Adequacy Pools. The current proposed BAL-008 does not provide the ability to do that and will therefore be a burden on many BAs.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
It is unclear why this activity cannot be accomplished under NERC's existing **Reliability Assessment Committee (RAS)** in a voluntary and collaborative fashion as the RAS currently performs both Summer and Winter Reliability Assessments. In fact, seasonal ERAs could replace the existing deterministic Summer/Winter Assessments currently performed under this umbrella. Consideration should also be given to how migrating this activity to a mandatory standard will impact the openness and sharing that is currently done both *within* and *outside* the group with interested stakeholders, including state regulators having purview over matters of resource adequacy. From an overall Standards Efficiency Review perspective, the latter 2/3 of BAL-008 (R5-R13) introduce a lot of bureaucracy and new administrative requirements in comparison to 1/3 of BAL-008 (R1-R4) which focuses on producing "reliability results."	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	No
Document Name	
Comment	
PSE agrees with WPP's response to this question, shown below. *We are not aware of any analysis or study determining that this proposal is cost-effective, and therefore do not support this statement. Since the proposed standard requires the BA to be responsible to meet the ERA studies, it will most likely require the hiring of specialized skill sets that are not currently on staff. This can have a significant cost impact to BAs when the resource adequacy analyses are shifted from the Resource Planners to the BAs. The cost/benefit has not been articulated by the Drafting Team, and when this questions was asked during a Drafting Team workshop, the Drafting Team admitted there was no analysis for cost effectiveness.*	

BAs, if given the opportunity, will try and pool their resources and create Emergency Energy Plans and form Resource Adequacy Pools. The current proposed BAL-008 does not provide the ability to do that and will therefore be a burden on many BAs.	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 1,3,5,6, Group Name Santee Cooper	
Answer	No
Document Name	
Comment	
Implementation of this standard will not be cost effective because the additional study work that will be required will likely require additional personnel.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power endorses the comments provided by the Western Power Pool.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 14	

Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	No
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren supports MISO's comments on this project.	
Likes 0	
Dislikes 0	

Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

We are not aware of any analysis or study determining that this proposal is cost-effective, and therefore do not support this statement. Since the proposed standard requires the BA to be responsible to meet the ERA studies, it will most likely require the hiring of specialized skill sets that are not currently on staff. This can have a significant cost impact to BAs when the resource adequacy analyses are shifted from the Resource Planners to the BAs. The cost/benefit has not been articulated by the Drafting Team, and when this questions was asked during a Drafting Team workshop, the Drafting Team admitted there was no analysis for cost effectiveness.

BAs, if given the opportunity, will try and pool their resources and create Emergency Energy Plans and form Resource Adequacy Pools. The current proposed BAL-008 does not provide the ability to do that and will therefore be a burden on many BAs.

Likes 0	
Dislikes 0	
Response	
Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group	
Answer	No
Document Name	
Comment	

CHPD supports WPP's response. It would be helpful to pool resources for seasonal planning purposes.

Likes 0	
Dislikes 0	
Response	
Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

BAs who would benefit from these types of studies are most likely already doing something similar to what is defined in this standard. They will likely only need to change their process to match the standard which will not be a significant expense. For other BAs, such as very small BAs and

generation only BAs, for example, who are not currently performing similar studies, acquiring the tools needed and hiring staff with the expertise to perform the studies will incur expenses far beyond any benefits they might realize from this process.	
Likes 0	
Dislikes 0	
Response	
Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy	
Answer	No
Document Name	
Comment	
DTE supports MISO's feedback	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
It is unclear why this activity cannot be accomplished under NERC's existing Reliability Assessment Committee (RAS) in a voluntary and collaborative fashion as the RAS currently performs both Summer and Winter Reliability Assessments. In fact, seasonal ERAs could replace the existing deterministic Summer/Winter Assessments currently performed under this umbrella. Consideration should also be given to how migrating this activity to a mandatory standard will impact the openness and sharing that is currently done both within and outside the group with interested stakeholders, including state regulators having purview over matters of resource adequacy. From an overall Standards Efficiency Review perspective, the latter 2/3 of BAL-008 (R5-R13) introduce a lot of bureaucracy and new administrative requirements in comparison to 1/3 of BAL-008 (R1-R4) which focuses on producing "reliability results."	
Likes 0	
Dislikes 0	
Response	
Bobbi Welch - Midcontinent ISO, Inc. - 2	

Answer	No
Document Name	
Comment	

MISO supports the comments of the SRC and MRO NSRF.

It is unclear why this activity cannot be accomplished under NERC's existing **Reliability Assessment Committee (RAS)** in a voluntary and collaborative fashion, as the RAS currently performs both Summer and Winter Reliability Assessments. In fact, seasonal ERAs could replace the existing deterministic Summer/Winter Assessments currently performed under this umbrella.

Consideration should also be given to how migrating this activity to a mandatory standard will harm the openness and sharing that is currently done both *within* and *outside* the group with interested stakeholders, including state regulators that have authority over matters of resource adequacy.

From an overall Standards Efficiency Review perspective, the latter 2/3 of BAL-008 (R5-R13) introduce unnecessary bureaucracy and new administrative requirements in comparison to the first 1/3 of BAL-008 (R1-R4), which seems to focus more on attempting to produce reliability results. Additionally, as detailed elsewhere in our comments, BAL-008 is currently substantively duplicative of EOP-011, TOP-002, and IRO-014 while simultaneously imposing additional administrative burdens that do not enhance system reliability. In addition, the standard presumes that BAs have access to fuel-related information that they do not possess and currently have no cost-effective method of obtaining. Removing the duplication and fully addressing the information access issues are necessary prerequisites to meeting the Standards Authorization Request in a cost-effective manner.

Likes 0	
Dislikes 0	
Response	
Reed Adam - Seattle City Light - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

We are not aware of any analysis or study determining that this proposal is cost-effective, and therefore do not support this statement. Since the proposed standard requires the BA to be
responsible to meet the ERA studies, it will most likely require the hiring of specialized skill sets that are not currently on staff. This can have a significant cost impact to BAs when the resource adequacy analyses are shifted from the Resource Planners to the BAs. The cost/benefit has not been articulated by the Drafting Team, and when this questions was asked during a Drafting Team workshop, the Drafting Team admitted there was no analysis for cost effectiveness.
BAs, if given the opportunity, will try and pool their resources and create Emergency Energy Plans and form Resource Adequacy Pools. The current proposed BAL-

Likes 0	
Dislikes 0	
Response	
Michael Jang - Seattle City Light - 1,3,4,5,6	

Answer	No
Document Name	
Comment	
SCL is in support and alignmnet with WPP's & Idaho's submitted comments.	
Likes 0	
Dislikes 0	
Response	
Daren Brubaker - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
I agree with the comments provided by Western Power Pool.	
Likes 0	
Dislikes 0	
Response	
Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Seattle City Light agrees with WPP Submitted Comment.	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	

Comment	
Idaho Power agrees with WPP’s response to this question, shown below. We are not aware of any analysis or study determining that this proposal is cost-effective, and therefore do not support this statement. Since the proposed standard requires the BA to be responsible to meet the ERA studies, it will most likely require the hiring of specialized skill sets that are not currently on staff. This can have a significant cost impact to BAs when the resource adequacy analyses are shifted from the Resource Planners to the BAs. The cost/benefit has not been articulated by the Drafting Team, and when this questions was asked during a Drafting Team workshop, the Drafting Team admitted there was no analysis for cost effectiveness. BAs, if given the opportunity, will try and pool their resources and create Emergency Energy Plans and form Resource Adequacy Pools. The current proposed BAL-008 does not provide the ability to do that and will therefore be a burden on many BAs.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	

Answer	Yes
Document Name	
Comment	
Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Greg Sorenson - ReliabilityFirst - 10 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC	
Answer	
Document Name	
Comment	
No comment on cost-effectiveness.	
Likes 0	
Dislikes 0	

Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	
Document Name	
Comment	
TEPC agrees with EEI's comments -	
Likes 0	
Dislikes 0	
Response	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
LG&E & KU agree with comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 1,3,5,6	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC	
Answer	
Document Name	
Comment	
PNM does not have a comment or answer to this question at this time.	
Likes 0	
Dislikes 0	
Response	

Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy’s vision is a highly reliable and secure bulk power system and will therefore not comment on cost-effectiveness.	
Likes 0	
Dislikes 0	
Response	

15. BAL-008-1 Seasonal ERAs: Provide any BAL-008-1 additional comments for the SDT to consider, if desired.

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	
Document Name	
Comment	

Idaho Power agrees with WPP's response to this question, shown below.

In general, the need for Energy Assurance with Energy-Constrained Resources is understood. The drafting team has worked hard to address the needs to ensure energy adequacy and has invested a lot of time discussing and addressing concerns in the development of this standard. It is difficult to support the proposed standard because it is not performance-based and introduces a lot of administrative processes. It introduces a lot of compliance risk without enhancing BES reliability. The fill-in-the blank concept adds additional risk and incentivizes entities to meet the lowest common denominator of compliance, rather than encouraging exceptionalism. The proposal may seem workable from a practicable sense, but when enforced, the standard has a lot of subjective language that will be problematic. Requiring BA's to be responsible for resource adequacy seems like the wrong functional home for the ERA when that was typically the role of the Resource Planners.

The drafting team should focus on a coordinated resource plan as the end goal. It should consider where some entities have already made progress in developing solutions to address energy adequacy, and it should not exclude those programs that are already in existence.

RCs who oversee large BAs and markets should not find the requirements in this proposal too onerous due to the economy of scale. RCs who oversee large numbers of BAs, on the other hand, will have challenges in meeting the review timelines. The RCs will also struggle to ensure that energy adequacy is sufficiently coordinated amongst the multiple BAs. Seams issues will need to be addressed where there are adjacent BAs and RCs competing for the same resources.

Likes 0	
Dislikes 0	
Response	

Chris Shultz - Seattle City Light - 1,3,4,5,6	
Answer	
Document Name	
Comment	

Seattle City Light agrees with WPP Submitted Comment.

Likes 0	
Dislikes 0	
Response	

Daren Brubaker - Seattle City Light - 1,3,4,5,6

Answer	
Document Name	

Comment

I agree with the comments provided by Western Power Pool.

Likes 0	
Dislikes 0	

Response

Michael Jang - Seattle City Light - 1,3,4,5,6

Answer	
Document Name	

Comment

SCL is in support and alignmnet with WPP's & Idaho's submitted comments.

Likes 0	
Dislikes 0	

Response

Reed Adam - Seattle City Light - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

In general, the need for Energy Assurance with Energy-Constrained Resources is understood. The drafting team has worked hard to address the needs to ensure energy adequacy and has invested a lot of time discussing and addressing concerns in the development of this standard. It is difficult to support the proposed standard because it is not performance-based and introduces a lot of administrative processes. It introduces a lot of compliance risk without enhancing BES reliability. The fill-in-the blank concept adds additional risk and incentivizes entities to meet the lowest common denominator of compliance, rather than encouraging exceptionalism. The proposal may seem workable from a practicable sense, but when enforced, the standard has a lot of subjective language that will be problematic. Requiring BA's to be responsible for resource adequacy seems like the wrong functional home for the ERA when that was typically the role of the Resource Planners.

The drafting team should focus on a coordinated resource plan as the end goal. It should consider where some entities have already made progress in developing solutions to address energy adequacy, and it should not exclude those programs that are already in existence.

RCs who oversee large BAs and markets should not find the requirements in this proposal too onerous due to the economy of scale. RCs who oversee large numbers of BAs, on the other hand, will have challenges in meeting the review timelines. The RCs will also struggle to ensure that energy adequacy is sufficiently coordinated amongst the multiple BAs. Seams issues will need to be addressed where there are adjacent BAs and RCs competing for the same resources.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Duke Energy supports proposed EEI language modifications for Question 15.

Likes 0	
Dislikes 0	

Response

Bobbi Welch - Midcontinent ISO, Inc. - 2

Answer	
Document Name	

Comment

MISO supports the comments of the SRC and MRO NSRF.

While seasonal studies may be valuable, it is unclear why this activity cannot be accomplished by NERC's existing **Reliability Assessment Committee (RAS)** in a voluntary and collaborative fashion as the RAS, in working with the Regional Entities, currently performs both Summer and Winter Reliability Assessments. In fact, seasonal ERAs could replace the existing deterministic Summer/Winter studies. Consideration should be given to how migrating this activity to a mandatory standard will harm the openness and sharing that is currently done in these groups.

Until a final decision can be made with respect to how seasonal studies are performed, the SRC supports the move to develop separate standards for seasonal ERAs and near-term ERAs.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment	

The MRO NSRF is supportive of performing seasonal studies.

That said, it is unclear why this activity cannot be accomplished under NERC's existing Reliability Assessment Committee (RAS) in a voluntary and collaborative fashion as the RAS, in working with the Regional Entities, currently performs both Summer and Winter Reliability Assessments. In fact, seasonal ERAs could replace the existing deterministic Summer/Winter studies. Consideration should be given to how migrating this activity to a mandatory standard will impact the openness and sharing that is currently done in these groups.

Until a final decision can be made with respect to how seasonal studies are performed, the MRO NSRF supports the move to develop separate standards for seasonal ERAs and near-term ERAs.

Likes 0	
Dislikes 0	

Response

Mohamad Elhusseini - DTE Energy - Detroit Edison Company - 3,5, Group Name DTE Energy

Answer	
Document Name	

Comment

DTE supports MISO's feedback

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1,3,5

Answer	
Document Name	

Comment

1. The first sentence of the Purpose section appears incomplete. "To the risks associated with Energy Emergencies … " should read "To assess the risks associated with Energy Emergencies…" Also the second sentence provides additional background information that is appropriate for the Technical Rationale rather than the Purpose section of the Standard.

2. The VSL Table for Requirement R1 of BAL-001-8 indicates a Moderate VSL if the BA fails to maintain the ERA Process annually. R1 does not specify a minimum required maintenance interval. BC Hydro recommend reviewing the VSL Table and revising for alignment between Requirements and associated VSLs.

3. The VSL Table for Requirement R13 identifies Severity Levels based on an RC failing to notify starting at the 24-hour mark. Requirement R13 mandates that the RC notifies applicable entities within seven calendar days. BC Hydro recommends that the VSL Table be reviewed and revised as necessary for alignment with the Requirements.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3,4,5,6, Group Name WEC Energy Group

Answer	
Document Name	

Comment

WEC Energy Group supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Jennifer Weber - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - Public Service Company of New Mexico - 1,3 - WECC

Answer	
Document Name	

Comment

PNM supports EEI recommended changes to the BAL-007-1 purpose statement.

Likes 0	
Dislikes 0	

Response

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

LG&E & KU agree with comments provided by EEI, with the following additional feedback on the wording for consistency:

- Page 3: B (R2) – Change "…vary one or more of the following conditions to stress its System…" to "…vary one or more of the following conditions by a sufficient amount to stress the System…" to match wording in BAL 007-1.
- Page 5: B (R7) – Change "The Balancing Authority…" to "Each Balancing Authority…" to match rest of document wording.
- Page 5: B (M7) – Make the following changes: 1. Add reference to updates to match wording in R7 and reference to Requirements R1 through R3 to match wording in R7; 2. Remove reference to provide to Reliability Coordinator since that is detailed in R8/M8; 3. Add reference to calendar months to match wording in R7. ("Each Balancing Authority shall have evidence that it reviewed and updated its seasonal ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 at least once every 24 calendar months, in accordance with Requirement R7.")
- Page 5: B (M9) – Change "…the review within 60 days of…" to "…the review within 60 calendar days of…" to match wording in R9.
- Page 9: Violation Severity Table (R3) (High Violation) – Change "…maintained Operating Plan(s) but…" to "…maintained Operating Plan(s) to minimize forecasted Energy Emergencies, as identified in the seasonal ERA, but…" to match wording in R3.
- Page 10: Violation Severity Table (R7) (High Violation) – Remove reference to providing to Reliability Coordinator on mutually agreed schedule since that is detailed in R8 and add reference to calendar months to match wording in R7. ("…but failed to update within 24 calendar months.")
- Page 10: Violation Severity Table (R7) (Severe Violation) – Remove "…to its Reliability Coordinator" since R7 does not reference providing the Reliability Coordinator as that is included in R8. Change "…to review or update…" to "…review and update, if necessary,…" to match wording in R7.
- Page 10: Violation Severity Table (R8) (High Violation) – Change "…but failed to submit to the Reliability Coordinator within 24 months" to "…but failed to submit to the Reliability Coordinator within 24 calendar months" to match wording in R8.
- Page 10: Violation Severity Table (R9) (Severe Violation) – Change "…Reliability Coordinator failed to review the information in Requirement R8 for coordination…" to "…Reliability Coordinator failed to review each submittal for coordination…" match wording in R9 high severity.
- Page 10: Violation Severity Table (R10) (High Violation) – Change "R7" to "R8" to match R10 wording.
- Page 10: Violation Severity Table (R10) (Severe Violation) – Change "R7" to "R8" to match R10 wording.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

To align with NERC's Reliability Principles, BPA believes NERC drafting teams should strive to make reliability standards as clear as possible, especially regarding each responsible entity's authorities and responsibilities. BPA's understanding is that NERC is relying on TOP-003-5 for a Balancing Authority's (BA) authority to require the information needed to conduct the Energy Reliability Assessments under proposed BAL-007-1 and BAL-008-1. However, it's not clear the proposed standards are utilizing a BA's authority to require information under TOP-003-5. It requires an entity to refer to another suite of reliability standards to find requirements that could potentially empower a BA to require the necessary information, and put other entities on notice that they must provide the required information.

For clarity and effectiveness of the proposed standards, BPA suggests revising the Technical Rationale document by outlining a BA's authority to request data, and the responsibility/obligation for other entities to provide data via TOP-003-5. By issuing a clarification that TOP-003 does apply, NERC could empower BAs to obtain the data they need, as BPA believes TOP-003 intended.

Given that the fuel and future dispatch level of generation in current bilateral markets of the Pacific Northwest is considered 'market sensitive' information, generator owners and operators may not be willing to share such information with BAs or Transmission System Providers. As a result, the standards need to make absolutely clear that providing such information is required

Likes 1	Public Utility District No. 1 of Snohomish County, 1, Rhoads Alyssia
Dislikes 0	

Response

Anne Kronshage - Public Utility District No. 1 of Chelan County - 1,3,5,6, Group Name Public Utility District No. 1 of Chelan County - Voting Group

Answer	
Document Name	

Comment

For R8, CHPD suggests adjusting the language to "...mutually agreed upon schedule and format."

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Southern Company supports the EEI comments and agrees with the EEI language changes for the Purpose statement.

Likes 0	
Dislikes 0	

Response
Kimberly Turco - Constellation - 5,6

Answer	
Document Name	

Comment
Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	
Document Name	

Comment
TEPC agrees with EEI's comments - EEI does not agree that the language currently contained in the purpose statement for BAL-008-1 is sufficiently clear. And while we do not disagree with the last sentence in the purpose, it does not provide any meaningful value to the purpose.

Likes 0	
Dislikes 0	

Response
Kevin Conway - Western Power Pool - 4

Answer	
Document Name	

Comment
In general, the need for Energy Assurance with Energy-Constrained Resources is understood. The drafting team has worked hard to address the needs to ensure energy adequacy and has invested a lot of time discussing and addressing concerns in the development of this standard. It is difficult to support the proposed standard because it is not performance-based and introduces a lot of administrative processes. It introduces a lot of compliance risk without enhancing BES reliability. The fill-in-the blank concept adds additional risk and incentivizes entities to meet the lowest common denominator of compliance, rather than encouraging exceptionalism. The proposal may seem workable from a practicable sense, but when enforced, the standard has a lot of subjective language that will be problematic. Requiring BA’s to be responsible for resource adequacy seems like the wrong functional home for the ERA when that was typically the role of the Resource Planners.

The drafting team should focus on a coordinated resource plan as the end goal. It should consider where some entities have already made progress in developing solutions to address energy adequacy, and it should not exclude those programs that are already in existence.

RCs who oversee large BAs and markets should not find the requirements in this proposal too onerous due to the economy of scale. RCs who oversee large numbers of BAs, on the other hand, will have challenges in meeting the review timelines. The RCs will also struggle to ensure that energy adequacy is sufficiently coordinated amongst the multiple BAs. Seams issues will need to be addressed where there are adjacent BAs and RCs competing for the same resources.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC

Answer	
Document Name	

Comment

The Evidence Retention section needs to be addressed as it mentions the “near-term” time horizon. Additionally, the act of submitting /reviewing ERA (and other items mentioned) occurs on a time period that could be longer than the retention requirements. Evidence should be retained to allow an entity to easily demonstrate compliance. Resource Planner is not called out (but as previously commented, should the RP be changed?).

In the VSLs a general note—Is the expectation for a single method or multiple methods of Scenario creation? Seems like it should be methods to match Standard.

R1 Moderate VSL mentions maintaining the ERA process “annually” which is not part of the Requirement. The High and Severe R1 VSLs do not cover 1.5 and should to be accurate.

R7 VSL for High and Severe need adjusting as the Reliability Coordinator submittal is not in the Requirement. Suggest for High- “The Balancing Authority reviewed the seasonal ERA process, Scenarios or methods of Scenario creation, and Operating Plan(s) but did not update the materials (as needed) within 24 calendar months.” Severe VSL- “The Balancing Authority did not review and update seasonal ERA process, Scenarios or methods of Scenario creation and Operating Plan(s) within 24 calendar months.”

R8 High VSL needs to add “calendar” in front of months to match Requirement.

R9- Is the RC to notify “each” BA or just the BA submitting information? If former, VSL would need adjustment

R10 High VSL- Should it read “The Balancing Authority addressed **the** reliability risks…”? What happens if the BA does not address all the reliability risks identified? R10 VSLs should reference R8 not R7.

R13 VSL-All the VSLs do not match the “seven calendar days” called out in the Requirement language. Correct spelling in Severe for “Coordinator” towards end of sentence. The High VSL added “Area” to the neighboring Reliability Coordinator—need to remove it. The VSL needs to be clearly understood in that if the RC notified a Balancing Authority but failed to notify any TOPs there would be a reliability concern and possibly a violation. Suggest adding “one or more” in front of TOP.

Likes 0	

Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
Ameren supports MISO's comments on this project.	
Likes 0	
Dislikes 0	
Response	
Nazra Gladu - Manitoba Hydro - 1,3,5,6	
Answer	
Document Name	
Comment	
Manitoba Hydro supports comments of MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
Minnesota Power supports MRO’s NERC Standards Review Forum’s (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Evergy - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 15	
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 endorses the comments provided by the Western Power Pool.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1,3	
Answer	
Document Name	
Comment	
Exelon does not oppose BAL-008, we support EEI's comments to clarify the Purpose statement.	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6	

Answer	
Document Name	
Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	
Document Name	
Comment	
PSE agrees with WPP's response to this question. PSE doesn't see a need for a seasonal assessment in addition to the ERA specified in BAL-007. There are no additional reliability actions the BA can perform in this time horizon that aren't also available in the BAL-007 time horizon. Our preference would be to implement the BAL-007 first and then pursue a long term planning resource adequacy standard where resource proposals could be solicited. This approach would make more sense and provide better reliability than creating duplicative assessments in the operations planning time horizon.	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Quebec (HQ) - 2 - NPCC	
Answer	
Document Name	
Comment	
HQ recognizes that the work the drafting team has put in the development of these standards and is supportive of performing seasonal studies. However we are concerned that certain requirements as they are written add an unnecessary burden in the process.	
Likes 0	
Dislikes 0	
Response	

Keith Jonassen - ISO New England, Inc. - 2 - NPCC	
Answer	
Document Name	
Comment	
No Additional Comments	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC RSC support the project.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	

Document Name	
Comment	

EEI does not agree that the language currently contained in the purpose statement for BAL-008-1 is sufficiently clear. And while we do not disagree with the last sentence in the purpose, it does not provide meaningful value to the purpose. To address our concerns, we offer the following proposed changes to the Purpose statement:

Purpose: To assess**, report and plan for energy constraints** associated with Energy Emergencies in the seasonal time horizon.

Likes 0	
Dislikes 0	
Response	

Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6

Answer	
Document Name	
Comment	

Puget Sound Energy (PSE) agrees with WPP's response to this question. Additional PSE comments are shown below.

PSE doesn't see a need for a seasonal assessment in addition to the ERA specified in BAL-007. There are no additional reliability actions the BA can perform in this time horizon that aren't also available in the BAL-007 time horizon. Our preference would be to implement the BAL-007 first and then pursue a long term planning resource adequacy standard where resource proposals could be solicited. This approach would make more sense and provide better reliability than creating duplicative assessments in the operations planning time horizon.

Likes 0	
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 1,3,4,5,6

Answer	
Document Name	
Comment	

Seminole agrees with FRCC's comments below

The FRCC agrees with and supports the Edison Electric Institute (EEI) comments on question #15:
EEI does not agree that the language currently contained in the purpose statement for BAL-008-1 is sufficiently clear. And while we do not disagree with

the last sentence in the purpose, it does not provide meaningful value to the purpose. To address our concerns, we offer the following proposed changes to the Purpose statement:

Purpose: To assess, report and plan mitigations for energy constraints the risks associated with Energy Emergencies in the seasonal time horizon and take appropriate actions to address identified risk. As the Bulk-Power System becomes more reliant upon energy-constrained and variable resources, traditional capacity-based planning methods and strategies might not identify energy-related risks to reliable System operation.

Likes 0	
Dislikes 0	

Response

LaKenya Vannorman - Florida Municipal Power Agency - 3,5,6 - SERC, Group Name Florida Municipal Power Agency (FMPA)

Answer	
Document Name	

Comment

FMPA supports FRCC/ORS comments with the exception of FRCC/ORS perspectives on adding to the TOP-002 burden.

Likes 0	
Dislikes 0	

Response

Daniela Atanasovski - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

APS proposes revisions to the purpose statement. Within the Purpose statement of BAL-008-1 Draft 1 it states: “To assess the risks associated with Energy Emergencies in the seasonal time horizon and ***take appropriate actions*** to address identified risk.”

APS proposes the SDT remove “take appropriate actions” and replace with “develop plans” as stated below: “To assess the risks associated with Energy Emergencies in the seasonal time horizon and ***develop plans*** to address identified risk.”

Additionally, in the Purpose Statement and Requirement 1, the term "seasonal time horizon" is not listed in the NERC glossary of terms or in the NERC Time Horizon criteria and referenced in the standard. The SDT should consider revising “seasonal time horizon” to "seasonal time period" to avoid confusion with NERC defined Time Horizons.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SRC Energy Assurance	
Answer	
Document Name	
Comment	
While seasonal studies may be valuable, it is unclear why this activity cannot be accomplished by NERC's existing Reliability Assessment Committee (RAS) in a voluntary and collaborative fashion as the RAS, in working with the Regional Entities, currently performs both Summer and Winter Reliability Assessments. In fact, seasonal ERAs could replace the existing deterministic Summer/Winter studies. Consideration should be given to how migrating this activity to a mandatory standard will harm the openness and sharing that is currently done in these groups. Until a final decision can be made with respect to how seasonal studies are performed, the SRC supports the move to develop separate standards for seasonal ERAs and near-term ERAs.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Vince Ordax - Florida Reliability Coordinating Council – Member Services Division - 8	
Answer	
Document Name	
Comment	
The FRCC agrees with and supports the Edison Electric Institute (EEI) comments on question #15: EEI does not agree that the language currently contained in the purpose statement for BAL-008-1 is sufficiently clear. And while we do not disagree with the last sentence in the purpose, it does	

not provide meaningful value to the purpose. To address our concerns, we offer the following proposed changes to the Purpose statement:

Purpose: To assess, report and plan for energy constraints associated with Energy Emergencies in the seasonal time horizon.

Likes 0	
Dislikes 0	

Response

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC, Group Name SPP RTO

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The concept of an "operating plan" and the corresponding process/documentation is a little opaque. In today's operating world the tools we utilize in short term planning can provide us up to 7 days of what we could consider an "operating plan" but that function doesn't materialize into an actual gen plan until we get to the day in question. Furthermore, when referencing BA it looks like it is tied more to real-time operations, so we are not sure of the need for the BA to be associated with the concept of leading an operating plan.

Secondly, we don't understand the need for anything beyond (1) plan, Requirement 3 opens the door for additional operating plans, which we are oppose to due to the number of plans we already produce today.

Lastly, it's not clear what is driving the need for submitting to the RC. Is this expected to be done daily? We are also not entirely comfortable with the idea of submitting something to the RC that moves beyond the day in question. Not sure what value or benefit there is in submitting to the RC for these forward days. We disagree with this requirement.

Likes 0	
Dislikes 0	

Response

Benjamin Widder - MGE Energy - Madison Gas and Electric Co. - 3,4	
Answer	
Document Name	
Comment	
Madison Gas and Electric supports the comments of the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	

Wayne Guttormson - SaskPower - 1	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	

Robert Blackney - Edison International - Southern California Edison Company - 1,3,5,6	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

Dmitriy Bazylyuk - NiSource - Northern Indiana Public Service Co. - 3,5,6, Group Name NIPSCO	
Answer	
Document Name	
Comment	
NIPSCO supports MISO's feedback.	
Likes 0	
Dislikes 0	
Response	
Chance Back - Muscatine Power and Water - 1,3,5,6	
Answer	
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	
Document Name	
Comment	
Pattern Energy supports Midwest Reliability Organization's NERC Standards Review Forum's (MRO NSRF) comments on this question.	
Likes 0	
Dislikes 0	
Response	

Submitted comments from Avista Corp. – Mike Magruder, Robert Follini

1. The standards drafting team (SDT) modified the Energy Reliability Assessment (ERA) definition based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification.

☒ Yes
☐ No
Comments:

2. Based on industry feedback, the SDT updated Requirement R1 to clarify what near-term ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No
Comments: We agree with EEI’s comments.

3. The SDT updated Requirements R2 through Requirement R8 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No
Comments: We agree with EEI’s comments.

4. The SDT proposes entities use forecasted Demand profiles for the time interval under study for the BAL-007 assessment. The SDT’s goal is to align measures for ERAs with those used for EOP-011. Actions taken as part of a BAL-007 Operating Plan should be targeted to minimize any Energy Emergency events. Do you agree with the updated proposed language in Requirement R8? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☒ Yes
☐ No
Comments:

5. The SDT updated Requirement R9 based on industry feedback. Do you agree with the updated proposed language in Requirement R9? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No
Comments: We agree with EEI’s comments.

6. The SDT updated the implementation plan to allow for 18 months for Requirements R1 through R3 and 24 months for Requirements R4 through Requirement R10 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No
Comments: We agree with EEI’s comments.

7. The SDT believes that fuel data information needed to address BAL-007-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☒ Yes
☐ No
Comments:

8. The SDT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request 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: No comment on the cost-effectiveness as we have not yet evaluated the impacts.

9. Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

Comments: See EEI's comments.

BAL-008-1 Seasonal ERAs

10. The SDT drafted BA-008-1 Requirement R1 to clarify what seasonal ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No

Comments: We agree with EEI's comments.

11. The SDT drafted BAL-008-1 Requirements R2 through R13 based on industry feedback regarding seasonal ERAs. Do you agree with the proposed requirements? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No

Comments: We agree with EEI's comments.

12. The SDT drafted the BAL-008-1 implementation plan to allow for 18 months for Requirements R1 through R6 and 24 months for Requirements R7-R13 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No

Comments: We agree with EEI's comments.

13. The SDT believes that fuel data information needed to address BAL-008-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☒ Yes
☐ No

Comments:

14. The SDT proposes that the newly proposed BAL-008-1 meets the Standards Authorization Request 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: No comment on the cost-effectiveness as we have not yet evaluated the impacts.

15. Provide any BAL-008-1 additional comments for the SDT to consider, if desired.

Comments: We support EEI's comments here.
In addition, the Applicability section (4) ascribes applicability to the Resource Planner. We are not aware a standard could be applicable to a Resource Planner. What is the registration criterion?

Submitted comments from Talen Energy – Donald Lock

1. The standards drafting team (SDT) modified the Energy Reliability Assessment (ERA) definition based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification.

☒ Yes
☐ No
Comments:

2. Based on industry feedback, the SDT updated Requirement R1 to clarify what near-term ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☒ Yes
☐ No
Comments:

3. The SDT updated Requirements R2 through Requirement R8 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No
Comments: The, “credible energy supply contingency,” and “credible fuel supply contingency,” of R2.2 lack adequate specificity, particularly as regards extreme winter storms. Plans based on the ECWT of EOP-012 would be insufficient, for example, because Winter Storm Uri, the 2014 Polar Vortex and other recent generation capacities involved below-ECWT temperatures. The same is true of, “Unplanned generator outages.” If ice storms wreak havoc among the wind sleet that case needs to be studied.

4. The SDT proposes entities use forecasted Demand profiles for the time interval under study for the BAL-007 assessment. The SDT’s goal is to align measures for ERAs with those used for EOP-011. Actions taken as part of a BAL-007 Operating Plan should be targeted to minimize any Energy Emergency events. Do you agree with the updated proposed language in Requirement R8? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No
Comments: See our comments for R2 above.

5. The SDT updated Requirement R9 based on industry feedback. Do you agree with the updated proposed language in Requirement R9? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☒ Yes
☐ No
Comments:

6. The SDT updated the implementation plan to allow for 18 months for Requirements R1 through R3 and 24 months for Requirements R4 through Requirement R10 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☒ Yes
☐ No
Comments:

7. The SDT believes that fuel data information needed to address BAL-007-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No

Comments: GOs'TOP-003 reporting of fuel supply and inventory concerns and fuel switching capabilities has very little to do with predicting NG insufficiencies during extreme winter storms. The issues of principal importance are NG production facility winterization, NG storage levels, localized pipeline capacity and the like, over which GOs have no control or knowledge.

8. The SDT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request in a cost-effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost-effective approaches, please provide your recommendation and, if appropriate, technical or procedural justification.

☐ Yes
☒ No
Comments:

9. Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

Comments: It does not address the issues at hand, per our comments above, and therefore cannot be cost-effective.

<u>BAL-008-1 Seasonal ERAs</u>

10. The SDT drafted BA-008-1 Requirement R1 to clarify what seasonal ERAs mean and to allow flexibility for Balancing Authorities when developing their process. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No
Comments: Seasonal average demand and capability have minimal importance. The paramount issue is generation supply adequacy for extreme events, especially worst-case winter storms.

11. The SDT drafted BAL-008-1 Requirements R2 through R13 based on industry feedback regarding seasonal ERAs. Do you agree with the proposed requirements? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No
Comments: The terms, "credible energy supply Contingency," "credible fuel supply Contingency" and, "Unplanned generator outage," lack adequate specificity, per our comments for R2 of BAL-007-1.

12. The SDT drafted the BAL-008-1 implementation plan to allow for 18 months for Requirements R1 through R6 and 24 months for Requirements R7-R13 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☒ Yes
☐ No
Comments:

13. The SDT believes that fuel data information needed to address BAL-008-1 can be achieved through TOP-003. Do you agree with this statement? If not, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

☐ Yes
☒ No
Comments: See our TOP-003-related comments for BAL-007.

14. The SDT proposes that the newly proposed BAL-008-1 meets the Standards Authorization Request 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: It does not address the issues at hand, and therefore cannot be cost-effective.

15. Provide any BAL-008-1 additional comments for the SDT to consider, if desired.

Comments:

NERC
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RELIABILITY CORPORATION

Response to Comments – Draft 2

NERC Project 2022-03 Energy Assurance with Energy-Constrained Resources

September 2024

RELIABILITY | RESILIENCE | SECURITY




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

Table of Contents

Introduction

NERC Project 2022-03 Energy Assurance with Energy-Constrained Resources drafting team (DT) is addressing energy assurance. This project will enhance reliability by requiring entities to perform energy reliability assessments to evaluate energy assurance and when predefined criteria are not met, develop Corrective Action Plan(s), Operating Plans, or other mitigating actions to address identified risks. Energy reliability assessments evaluate energy assurance across the operations time horizons by analyzing the expected resource mix availability (flexibility) and the expected availability of fuel during the study period.

There were 64 sets of responses, including comments from approximately 161 different people from approximately 99 companies representing 10 of the Industry Segments.

Additional information is available on the project page.

Background

Based on industry feedback, the DT modified the ERA definition, developed a new Near-term ERA definition to try to clear up confusion throughout the requirements, removed administrative burdens, updated language to provide flexibility, and removed subjective type language throughout the requirements.

Response to Comments Document Layout

The DT will be responding to all comments in a summary response report. Each chapter covers topics identified throughout the comments received (e.g., Applicability, Definition, Administrative, Requirements, etc.). Comments received are outlined at a high level in each chapter followed by the drafting team's response on how it considered the comment and the outcome of how the comment was addressed. If you have any questions, please contact Standards Developer, Jordan Mallory (Jordan.mallory@nerc.net).

Thank You

The drafting team thanks industry for your time in reviewing the proposed BAL-007-1 standard and providing comments and proposals for the drafting team's consideration. All comments received have been reviewed and discussed. Response to comments have been drafted in a summary response.

Standards Redundancy

TOP-002, TOP-003, and EOP-011

Industry Comment

Many industry commenters were concerned as to why the drafting team (DT) did not use existing standards, such as, TOP-002, TOP-003, and EOP-011 to address the scope of the project. Commenters continued to voice that Operating Plans seem to be the same Operating Plans generated from TOP-002. Some commenters expressed the duplicative nature of requirements from BAL-007 that seem similar to other reliability standards.

Drafting Team Response:

The Operational Planning Analyses and the Operating Plans performed and developed in TOP-002 are different than the Energy Reliability Assessments and Operating Plans proposed in BAL-007-1. TOP-002 is the standard for performing current- and next-day capacity assessments with minimal consideration for the energy required from fuel generation resources. Likewise, TOP-003 ensures that the Transmission Operator and Balancing Authority have the data needed for analysis but does not cover the actions needed for an ERA. Also, EOP-011 addresses the effects of operating emergencies in real-time but does not cover the actions needed for an ERA. In terms of performing assessments/analyses, ERAs are fairly similar to traditional capacity assessments, however they better represent the evolving resource mix and will grow in importance over the next many years.

Two items to consider between next-day assessments and ERAs are (1) the inclusion of the impacts of limited fuel supplies which leads to (2) the need for a longer time horizon. The specifics of each will be determined based mostly on the resource mix in each Balancing Authority Area.

TOP-002 covers today and tomorrow. BAL-007-1 extends that outlook to the next several weeks. Within the requirements of BAL-007-1, modeling limited supplies of fuel (including the variability of wind and solar irradiance in addition to fossil fuels) or planned fuel deliveries is necessary to fully examine forecasted conditions. It is imperative to model the performance of resources based on their actual ability to operate, not just simply their existence and status. Regional differences (specifically in what resource types are present in each BA) will drive what specific information is required, which is why it cannot be prescribed in the standard but must be determined by the entity performing the assessment. Longer time horizons (up to several weeks) may be necessary to account for fuel supply or the intentional utilization of electric storage within an area depending more on variable energy resources.

Operating Plans are where the real differences are between the two standards, and why longer time horizons can be most beneficial. BAL-007-1 actions are intended to complement and reduce the severity of TOP-002 and EOP-011 actions. TOP-002 Operating Plans are fairly limited in scope due to the time required to implement specific actions. Typically, TOP-002 Operating Plans call for actions from bringing online more generation to more extreme steps like voltage reductions, the depletion of required Operating Reserves, or the shedding of firm load. ERA Operating Plans will mostly take place further in advance but likely won't be as potentially extreme in nature. While they may have some of the same actions, once they're happening in real-time or near-real-time, operators have moved to TOP-002 or EOP-011 space. One example of actions that would be included in BAL-007-1 Operating Plans include expanded communication with regulators, neighboring areas, and the general public. This allows for those who will be impacted to be better prepared, leading to a more resilient recovery or potentially even being able to provide energy support when it would otherwise be unavailable. More targeted actions that would only be available to an entity performing an ERA would be the recall of long-recall-time outages, replenishment of stored fuels, better optimization of the use of existing stored fuels, and enhanced conservation efforts before experiencing more extreme conditions. The standard does not tell an entity how to complete its Operating Plans. The standard provides the requirements of what needs to be included in the Operating Plans. Some comments have been received over the course of this project asking if an entity could use its TOP-002 or EOP-011 plans. If you, as an entity, choose to update those Operating Plans to include BAL-007-1 information, that is up to the entity on how it is completed. The DT recognizes that entities can come to the same conclusion in many different ways and the standard does not preclude how an entity meets the requirements of a standard.

Fundamentally, TOP-002 could be reorganized to include the energy risks being addressed by BAL-007-1. But as of today, TOP-002 doesn’t require the energy considerations at the same level as BAL-007-1 and to draw a clear line between traditional capacity assessments and true energy assessments warrants a new standard that makes that distinction clear. Otherwise, TOP-002 is a shift in philosophies, not just wording.

BAL-007-1 Applicable Entity

Energy Reliability Assessments (ERA)

Industry Comment

Some commenters expressed that the BA, as identified in the current draft of BAL-007-1, is the wrong functional entity to address resources adequacy. The Resource Planner, as defined in the NERC ROP and NERC Glossary of Terms Used in the Reliability Standards, is the most appropriate functional entity to conduct ERAs. Arguably, the Resource Planner generally focuses on resource adequacy on “a long-term (generally [emphasis added] one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area”, but not for a short-term plan. It is the Resource Planner’s responsibility to “[Coordinate] with Transmission Planners, Transmission Service Providers, Reliability Coordinators, and Planning Coordinators on resource adequacy plans” (see NERC Functional Model). BAs are not typically staffed with planners who are familiar with assessing resource adequacy, and they rely on assessments from Resource Planners, Transmission Planners, and the Load-Serving Entities to develop their Operating Plans regarding such things as energy capacity and fuel availability.

Drafting Team Response:

The drafting team (DT) insists that Balancing Authorities are the best suited entities to perform Near-Term Energy Reliability Assessments. The assessments that have been accepted as the clear path forward differ from the current spectrum of existing assessments, and therefore don’t have a clearly defined responsible entity. It could be argued that very few entities have relevant experience in performing ERAs. The need is new and caused by the evolving resource mix, not something that would have been necessary just a few years ago.

The information and understanding of the resources that are included in a Near-Term ERA are most similar in nature to the current responsibilities of the BAs. This information includes generator capabilities and outage schedules, demand forecasts, and the expected transfers of energy between BAs. The BA is also responsible for the next-day planning and the operation of that same system, therefore the consequences of unacceptable results, an ERA performance will become the responsibility of the BA in the space of TOP-002. The Resource Planner, when evaluating conditions that are beyond a year, may be appropriate for longer term ERAs, but would be expected to lack the expertise of near-term aspects of this specific ERA. The BA would have a better understanding than an RP on items such as load forecasts vs load assumptions, outage schedules vs outage plans, and the volume of conditions that go into the assumptions made for interchange assumptions. While the base concepts may be similar in nature, the forecasts that provide input to a Near-Term ERAs are much more similar to the forecasts that initialize a next-day assessment than the assumptions that are used for longer term assessments. There will be a learning curve for whatever entity is responsible for ERA design and performance, but the learning curve will be most gradual for BAs.

Definitions

Energy Reliability Assessments (ERA)

Industry Comment

Many commenters expressed that a word appeared to be missing in the ERA definition. It was recommended to add the word “necessary” to the definition.

Drafting Team Response:

The drafting team (DT) updated the ERA definition. See updated definition below.

> **Energy Reliability Assessment (ERA)** – Evaluation of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated evaluation period.

Industry Comment:

Some commenters expressed the ERA definition applies under all the time horizons.

Drafting Team Response:

The drafting team agrees that the definition applies to all time horizons. To be more specific to near-term ERAs, an additional definition for “Near-Term Energy Reliability Assessment” was created. The additional details will help to set apart general ERAs from this specific type of ERA.

Requirement R1

Time Horizons

Industry Comment

Some commenters expressed that the "near-term time horizon" confuses this term with "Near-Term Planning Horizon" and "Near-Term Transmission Planning Horizon" that many entities are familiar with and are used in other NERC Standards.

Drafting Team Response:

The Drafting Team (DT) updated Requirement R1 to remove the near-term time horizon confusion.

Industry Comment

Some commenters expressed that the same ERA definition applies under all the time horizons.

Drafting Team Response:

The drafting team agrees that the definition applies to all time horizons. To be more specific to near-term ERAs, an additional definition for "Near-Term Energy Reliability Assessment" was created. The additional details will help to set apart general ERAs from this specific type of ERA.

Depletion of Fuel

Industry Comment

Many commenters expressed "Depletion of fuel" is overly prescriptive and one-sided (fails to consider replenishment) whereas "fuel supply" allows for a broad consideration of all fuel supply factors without requiring the BA to maintain documentation specific to the depletion of fuel for each generating resource.

Drafting Team Response:

The DT updated "depletion of fuel" throughout BAL-007-1 based on feedback received in place of "fuel supply".

Examples that should be in the Technical Rationale and the Standard

Industry Comment

Some commenters requested that the DT move "variable energy resources" and "electric storage" as examples to the Technical Rationale. It is misleading and incomplete for a standard to list a limited subset of resource technologies simply because they are "new." There will be other technologies in the future. Examples are more appropriately located in the Technical Rationale.

Drafting Team Response:

The DT removed variable energy resources and electric storage from BAL-007-1 and updated the Technical Rationale accordingly.

Unplanned Generator Outage Language

Industry Comment

Some commenters requested the DT add "unplanned generator outages" to Part 1.3.2 as this language will encompass all reasons leading to "unplanned generator outages/de-rates" and not limit it to fuel supply alone.

Drafting Team Response:
The DT removed unplanned generator outages from the BAL-007-1. The prior draft included this requirement under the Scenarios defined in R2, however the current requirement under R1 to model "resource capabilities and operational limitations" allows for the BA to include unplanned outages. It also allows the BA to define their ERA such that unplanned outages are not included, so long as the BA documents that process.

Time Periods Unclear

Industry Comment
Some commenters requested clarification on the time period being assessed or the amount of time entities must spend performing the assessment. It is also unclear whether the language requires entities to begin a new ERA within two days of each operating day, or whether the language simply limits how far in the future the ERA may look.

Drafting Team Response:
The DT added a new proposed NERC Glossary of Term, "Near-term ERA." The DT feels that with the creation of this definition, it removes any confusion on what defines a Near-term ERA along with what is required throughout the BAL-007-1 standard.

Known Resources

Industry Comment
Some commenters requested the DT add the word "known" to resource capabilities and operations in Part 1.3.2 to avoid any ambiguity.

Drafting Team Response:
The DT did not add the word "known" in front of resource capabilities as the team finds this to be clear as written.

Similar Subpart Requirements

Industry Comment
Some commenters requested the DT remove one of the subparts that come across as one item being captured under the same subpart. Some commenters requested the DT remove "Transmission constraints" subpart as it is covered in the "resource capabilities" subpart. Additionally, other commenters requested that the DT keep the "Transmission constraints" subpart and delete the "resource capabilities" subpart.

Drafting Team Response:
The DT determined that both subparts were needed. The capability of resources can exceed the ability of the transmission system to transfer that energy to load centers. Transmission limitations won't change the resource capabilities besides the BAs ability to use the full output of generators or subsets of the generation fleet (e.g., export constrained areas restricting 1000 MW of generation to 800 MW, collectively). It is prudent to model resource and transmission constraints separately, as not all BAs will experience the latter.

Joint Work (E.g., RSG, WRAP, etc.)

Industry Comment
Some commenters expressed concern that BAL-007-1 R1 does not appear to allow BAs to collectively pool resources to produce regional or sub-regional ERAs. No flexibility or deference is given to Resource Planners and entities who elect to do these tasks under programs like the Western Resource Adequacy Program.

Drafting Team Response:

The DT updated the respective requirements to allow for BA to “individually or jointly with other Balancing Authorities,” work together as a collective group to complete the assessments required for BAL-007-1.

Requirements R2 through R3

Subjective language

Industry Comment

Many commenters expressed various subjective language throughout BAL-007-1. Below provides specific statements from entities:

- Requirement R2 uses the terms "credible" and "best" which are subjective and therefore not conducive to a measurable compliance assessment at audit. One entity recommends revising to eliminate reliance on these terms.
- Requirement R3 uses the term "minimize", which can be subject to interpretation.

Drafting Team Response:

The DT updated Requirement R2 and R3 to remove the subjective terms (e.g., credible, best, minimize) and ensure the language is drafted clearly.

Historical Requirement

Industry Comment

Some commenters do not agree that it is necessary to include "or historical" within subpart 2.3 because the BA already has awareness of the historical risks within their BA region and those risk factors would be factored into their assessment of what is a credible risk.

Drafting Team Response:

The DT updated Requirement R2 to state: "that have a historical precedent of occurring, as defined by the Balancing Authority, based on the best information available at the time of Scenario development." The team felt historical was important to be added into the subpart as parameters are needed, but it is solely up to the BA to determine which type of historical information is best.

Audit Concerns

Industry Comment

Some comments express that R2 is vague and ambiguous. It amounts to a fill-in-the-blank standard. This puts entities in a position where they create their own standard to be audited against. This creates a situation where many companies will choose to meet minimum compliance thresholds to not risk potential non-compliance. Entities who may want to put their best effort forward will be reluctant to do that because it will have a higher risk of non-compliance. R2 has no performance measurements associated with it specifying a required minimum level of performance. NERC Standards should be performance based, not administrative. Documentation of Scenarios, methods, and rationales will result in subjective enforcement. Enforcement staff will likely leverage the ability to audit based on the quality of their ERA, not their performance to improve reliability.

Drafting Team Response:

The DT redrafted Requirement R2 to address reliability and to ensure the requirement is clear in what is expected from an entity.

Requirements R4 through R7

Duplicative, Administrative Burden, and Cost-Effective Concern

Industry Comment

Many commenters expressed concern regarding the duplicative nature of requirements stated in BAL-007-1 that are redundant and overlap other standards such as TOP-002 and EOP-011 and are administrative in nature. There were many comments expressed concerning the cost, and the additional personnel that entities would need to hire to address these types of requirements. Below provides specific statements provided by entities:

- Requirement R5, as written, is vague and does not seem to provide value to reliability, particularly in the case of Operating Plans, many of which would be obsolete on a 24-month provision timeframe.
- Requirement R6 cites certain RC actions related to Requirement R5. Requirement R5 is an administrative requirement that simply obligates the BA to supply their near-term ERA process, Scenarios or methods and Operating Plan(s) at least once every 24 months. While Requirement R6 obligates the RC to review the R5 materials and notify each BA if revisions are needed to their ERA process, Scenarios or methods and Operating Plan(s) within 60 days. This is administrative and therefore should not have a VRF higher than Low.
- Eliminate BAL-007-1 requirements R3-R7 to remove duplication with EOP-011 requirements R2-R4. Since the goal of BAL-007-1 is to perform ERAs and provide the BA with more lead-time to address forecasted Energy Emergency Alerts (as defined in EOP-011, Attachment 1, Section B), it is unnecessary and duplicative for BAL-007-1 to include requirements addressing preparation for, and management of, emergencies because EOP-011 already covers this topic.

Drafting Team Response:

The DT removed Requirements R4 through R7 from BAL-007-1.

Requirements R8 through R10

Requirement R8

Industry Comment

Many commenters questioned why the Drafting Team elected to put the implementation of R1 as one of the last requirements. R8 should be combined with R2 or R3 as a performance requirement following the R1 requirement. Alternatively, R8 could be moved up to R3, and renumbering the current requirements R3 through R7.

Drafting Team Response

The DT combined R8 with R2 to read in sequential order.

EEA Language

Industry Comment

A variety of comments stated below regarding the EEA language in Requirement R9.

- This language seems to duplicate EOP-011.
- EEAs should be left for BAs to enter as currently defined. Issuing an EEA too far out will not carry much weight because circumstances will likely change the next day for a BA.
- R9 should be removed from BAL-007-1 as it reaches beyond the near-term scope of BAL-007-1 and falls within Real-time Operations, specifically EOP-011.
- The Requirement R9 (revised BAL-007-1 Draft 1 R8) now references the EOP-011 Attachment 1 Section B. EOP-011 Attachment 1 Section B also includes specific responsibilities in addition to the EEA Levels definitions. BC Hydro suggests that EEA Level Definitions are more appropriate in the NERC Glossary of Terms, and recommends against embedding requirements by reference to different Reliability Standards.

Drafting Team Response

It is important that EEAs remain in BAL-007-1. There are three EEA levels, two of which are associated with forecasted Energy Emergencies. The criteria for forecasted Energy Emergency apply also to Scenarios identified in Requirement 2. This level of granularity allows for the BA to design an Operating Plan that fits the specific situation. Some Scenarios may be expected to enter the lower levels of an Energy Emergency, and the actions in an Operating Plan should be appropriate for that combination.

Finally, by leveraging the existing terms used in EOP-011 for EEA, clear and well-understood definitions are already in place which require little to no training, beyond the advanced timing associated with BAL-007-1. BAs have existing interpretations of how they respond when nearing or entering an EEA and the existing interpretations are expected to be used, including those that involve interaction with Reserve Sharing Groups.

Below provides response to the variety of proposed options for placement of EEA.

1. EEA Definition – This project is slated as a high priority and is due by December 2024. Creating or moving current language into a definition historically takes more than one comment and ballot period to get it right. This project has gone through two comment and ballot periods and has one comment and ballot period left to meet its project objective. In addition, it would be a significant uplift to insert the EEA information from EOP-011 into a definition as it has a domino effect from the changes made and how the EOP-011 standard has been drafted. The team is not against something to this degree but does not feel it is the appropriate time to make this type of change within the development process and the stage of this project.
2. EEA information as an attachment to BAL-007-1 – There are many ways to address similar requirements within other standards. The team determined that keeping it within the BAL-007-1 pointing to EOP-011 is an

appropriate method and that any drafting team who updates EOP-011 is required to review other standards to ensure the changes do not impact what is required in the other standards associate.

Requirement R10

Industry Comment

Some commenters stated that “Requirement R10 lacks sufficient clarity to ensure that RC will not be needlessly burdened to report forecasted Energy Emergencies that do not pose imminent risk to BES reliability.”

Drafting Team Response

The DT updated Requirement R10 to be clear that the BA will maintain its respective documents and provide them to the RC every 24 calendar months. This should clear up confusion on there being a burden on the RC due to the requirements removed on the back and forth between the BA and RC. In this requirement it only requires the BA to provide information to the RC.

BAL-007-1 Implementation Plan and Cost Effectiveness

Implementation Plan

Industry Comment

Some entities requested the DT extend the time to comply with all requirements in BAL-007-1 or want to remove intermediate deadlines.

Proposal	Number Entities Supporting	Suggested Edits (Months from FERC Approval)	Total time
A	24	R1-R3 in 18 Months and R4-R10 in 24 Months	24 Months
B	14	24 Months for all requirements	24 Months
C	8	R1 in 12 Months, R4-R7 in 18 Months, and 24 Months for all requirements	24 Months
D	7	36 Months for all Requirements	36 Months

Drafting Team Response:

The DT updated the Implementation Plan by removing the phased-in requirements and BAL-007-1 will have an implementation timeframe of 24-months for all requirements.

With the removal of the administrative type requirements, the DT did not feel that 36-months had adequate justification for development, implementing, and maintaining of what is required in BAL-007-1.

Cost Effectiveness

Industry Comment

Many entities expressed concern regarding the cost to address the additional administrative type requirements added to BAL-007-1 and that additional resources would be needed to address these types of requirements.

Drafting Team Response:

The DT updated the respective requirements from BAL-007-1 to address the cost effectiveness concern of administrative burden.

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Reminder

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Additional Ballots and Non-binding Poll Open through Thursday, June 20, 2024

Now Available

Additional ballots for draft two of **BAL-007-1 - Near-term Energy Reliability Assessments** and initial ballots for draft one of **BAL-008-1 - Seasonal Energy Reliability Assessments** and their implementation plans, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Thursday, June 20, 2024**.

The standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

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

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

Note: Votes cast in previous ballots, will not carry over to additional ballots. It is the responsibility of the registered voter in the ballot pools to place votes again. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*

- *Please be mindful of ballot and comment period closing dates. We ask to* ***allow at least 48 hours*** *for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts* ***prior to the last day*** *of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources 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

UPDATED
Standards Announcement
Project 2022-03 Energy Assurance with Energy-Constrained Resources

Formal Comment Period Extended, Now Open through June 24, 2024

Now Available

The formal comment period for **BAL-007-1 - Near-term Energy Reliability Assessments** and **BAL-008-1 - Seasonal Energy Reliability Assessments** has been extended and is now open through **8 p.m. Eastern, Monday, June 24, 2024**.

Regarding BAL-007-1, 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.

Next Steps

Additional ballots for BAL-007-1 and initial ballots for BAL-008-1 and their implementation plans, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels have been extended and will now be conducted **June 11 – 24, 2024**.

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

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2022-03 Energy Assurance with Energy-Constrained Resources observer list" in the Description Box.

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NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Formal Comment Period Open through June 20, 2024
Ballot Pools for BAL-008-1 Open through June 5, 2024

Now Available

A 45-day formal comment period for draft two of **BAL-007-1 - Near-term Energy Reliability Assessments** and draft one of **BAL-008-1 - Seasonal Energy Reliability Assessments**, is open through **8 p.m. Eastern, Thursday, June 20, 2024**.

Regarding BAL-007-1, the standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Ballot Pools

The existing BAL-007-1 ballot pools were used for all the BAL-008-1 ballots. The BAL-008-1 ballot pools have been re-opened to allow stakeholders to join if they are not existing members. Registered Ballot Body voters can join the ballot pools here by **8 p.m. Eastern, Wednesday, June 5, 2024.**

- *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.*

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.

Next Steps

Additional ballots for BAL-007-1 and initial ballots for BAL-008-1 and their implementation plans, as well as non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **June 11 – 20, 2024**.

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

For more information or assistance, contact Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2022-03 Energy Assurance with Energy-Constrained Resources observer list" in the Description Box.

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BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-008-1 IN 1 ST
Voting Start Date: 6/11/2024 12:01:00 AM
Voting End Date: 6/24/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 249
Total Ballot Pool: 314
Quorum: 79.3
Quorum Established Date: 6/21/2024 1:57:58 PM
Weighted Segment Value: 16.84

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	87	1	1	0.02	48	0.98	0	20	18
Segment: 2	8	0.8	4	0.4	4	0.4	0	0	0
Segment: 3	69	1	0	0	42	1	1	11	15
Segment: 4	16	0.8	1	0.1	7	0.7	0	3	5
Segment: 5	74	1	3	0.07	40	0.93	0	12	19
Segment: 6	51	1	2	0.054	35	0.946	0	7	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0.1	0	0	1	0.1	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	8	0.5	4	0.4	1	0.1	0	2	1
Totals:	314	6.2	15	1.044	178	5.156	1	55	65

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Third-Party Comments
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		None	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		None	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Third-Party Comments
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Third-Party Comments
1	Eversource Energy	Joshua London		Negative	Third-Party Comments
1	Exelon	Daniel Gacek		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Third-Party Comments
1	Portland General Electric Co.	Brooke Jockin		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Third-Party Comments
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Third-Party Comments
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Negative	Third-Party Comments
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Third-Party Comments
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Third-Party Comments
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Third-Party Comments
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	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Third-Party Comments
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Third-Party Comments
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Third-Party Comments
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	Dominion - Dominion Virginia Power	Victoria Crider		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Third-Party Comments
3	Eversource Energy	Vicki O'Leary		Negative	Third-Party Comments
3	Exelon	Kinte Whitehead		Abstain	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	Negative	Third-Party Comments
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Negative	Third-Party Comments
3	MEAG Power	Roger Brand	Rebika Yitna	None	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
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	Richard Machado		Negative	Third-Party Comments
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	Northern California Power Agency	Michael Whitney		None	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	Orlando Utilities Commission	Ballard Mutters		Negative	No Comment Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Platte River Power Authority	Richard Kiess		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Third-Party Comments
3	Portland General Electric Co.	Mayra Franco		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Third-Party Comments
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Third-Party Comments
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Seattle City Light	Zenon O'young-Chu	Reed Adam	Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Third-Party Comments
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Third-Party Comments
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		None	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Third-Party Comments
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Third-Party Comments
4	Western Power Pool	Kevin Conway		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Third-Party Comments
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	Calpine Corporation	Whitney Wallace		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Negative	Third-Party Comments
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Third-Party Comments
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Third-Party Comments
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
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	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Third-Party Comments
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
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		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Third-Party Comments
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Third-Party Comments
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seattle City Light	Chris Shultz		Negative	Third-Party Comments
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Third-Party Comments
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Third-Party Comments
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Third-Party Comments
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
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.	Michelle Hribar		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Third-Party Comments
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Third-Party Comments
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Third-Party Comments
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Third-Party Comments
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres		Abstain	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Manitoba Hydro	Brandin Stoesz		Negative	Third-Party Comments
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.	Dmitriy Bazylyuk		Negative	Third-Party Comments
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Negative	Third-Party Comments
6	Puget Sound Energy, Inc.	Heather Pierce		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Third-Party Comments
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
6	Seattle City Light	Daren Brubaker		Negative	Third-Party Comments
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Third-Party Comments
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Third-Party Comments
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Third-Party Comments
6	Western Area Power Administration	Jennifer Neville	Kimberly Bentley	Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Abstain	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		None	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

Showing 1 to 314 of 314 entries

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BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-008-1 Implementation Plan IN 1 OT
Voting Start Date: 6/11/2024 12:01:00 AM
Voting End Date: 6/24/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 241
Total Ballot Pool: 307
Quorum: 78.5
Quorum Established Date: 6/24/2024 9:27:47 AM
Weighted Segment Value: 15.51

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	86	1	3	0.063	45	0.938	0	20	18
Segment: 2	8	0.8	2	0.2	6	0.6	0	0	0
Segment: 3	66	1	1	0.026	37	0.974	1	12	15
Segment: 4	16	0.8	0	0	8	0.8	0	3	5
Segment: 5	72	1	4	0.103	35	0.897	0	13	20
Segment: 6	50	1	3	0.086	32	0.914	0	8	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0.1	0	0	1	0.1	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	8	0.6	5	0.5	1	0.1	0	1	1
Totals:	307	6.3	18	0.977	165	5.323	1	57	66

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Third-Party Comments
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Third-Party Comments
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		None	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		None	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Third-Party Comments
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Third-Party Comments
1	Eversource Energy	Joshua London		Negative	Third-Party Comments
1	Exelon	Daniel Gacek		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Third-Party Comments
1	Portland General Electric Co.	Brooke Jockin		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Third-Party Comments
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Third-Party Comments
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Third-Party Comments
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Third-Party Comments
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Independent Electricity System Operator	Helen Lainis		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)	Joshua Phillips	Shannon Mickens	Negative	Comments Submitted
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Third-Party Comments
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Third-Party Comments
3	Austin Energy	Lovita Griffin		Abstain	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Third-Party Comments
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	Dominion - Dominion Virginia Power	Victoria Crider		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Evergy	Marcus Moor	Hayden Maples	Negative	Third-Party Comments
3	Eversource Energy	Vicki O'Leary		Negative	Third-Party Comments
3	Exelon	Kinte Whitehead		Abstain	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MEAG Power	Roger Brand	Rebika Yitna	None	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
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	Richard Machado		Negative	Third-Party Comments
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	Northern California Power Agency	Michael Whitney		None	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	Orlando Utilities Commission	Ballard Mutters		Negative	No Comment Submitted
3	Platte River Power Authority	Richard Kiess		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Third-Party Comments
3	Portland General Electric Co.	Mayra Franco		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Third-Party Comments
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Third-Party Comments
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Third-Party Comments
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Third-Party Comments
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		None	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Third-Party Comments
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Carver Powers		Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Third-Party Comments
4	Western Power Pool	Kevin Conway		Negative	Comments Submitted
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Third-Party Comments
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	Calpine Corporation	Whitney Wallace		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Negative	Third-Party Comments
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
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	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Third-Party Comments
5	Northern California Power Agency	Jeremy Lawson		None	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
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		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Chelan County	Rebecca Zahler		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Third-Party Comments
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Third-Party Comments
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Third-Party Comments
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Third-Party Comments
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
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.	Michelle Hribar		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Third-Party Comments
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Third-Party Comments
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Third-Party Comments
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Third-Party Comments
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres		Abstain	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Third-Party Comments
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Negative	Third-Party Comments
6	Puget Sound Energy, Inc.	Heather Pierce		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Third-Party Comments
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Third-Party Comments
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Third-Party Comments
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Third-Party Comments
6	Western Area Power Administration	Jennifer Neville	Kimberly Bentley	Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		None	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

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Showing 1 to 307 of 307 entries

BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-008-1 | Non-binding Poll IN 1 NB
Voting Start Date: 6/11/2024 12:01:00 AM
Voting End Date: 6/24/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 226
Total Ballot Pool: 298
Quorum: 75.84
Quorum Established Date: 6/24/2024 6:41:16 PM
Weighted Segment Value: 9.21

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	83	1	1	0.026	38	0.974	25	19
Segment: 2	7	0.5	2	0.2	3	0.3	2	0
Segment: 3	65	1	0	0	33	1	16	16
Segment: 4	16	0.8	1	0.1	7	0.7	3	5
Segment: 5	70	1	3	0.091	30	0.909	16	21
Segment: 6	48	1	2	0.071	26	0.929	10	10
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0.1	0	0	1	0.1	0	0
Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	8	0.5	5	0.5	0	0	2	1
Totals:	298	5.9	14	0.988	138	4.912	74	72

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		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		None	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Duke Energy	Katherine Street		None	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	JEA	Joseph McClung		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker		None	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		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Chelan County	Diane E Landry		Negative	Comments Submitted
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 2 of Grant County, Washington	Joanne Anderson		None	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		None	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	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		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	Anaheim Public Utilities Dept.	Agustin Torres		None	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Victoria Crider		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Abstain	N/A
3	Georgia System Operations Corporation	Scott McGough		Abstain	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Comments Submitted
3	MEAG Power	Roger Brand	Rebika Yitna	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	Richard Machado		Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		None	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	Orlando Utilities Commission	Ballard Mutters		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
3	Platte River Power Authority	Richard Kiess		Abstain	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Public Utility District No. 1 of Chelan County	Joyce Gundry		Negative	Comments Submitted
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	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		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Austin Energy	Tony Hua		None	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	Georgia System Operations Corporation	Katrina Lyons		None	N/A
4	Illinois Municipal Electric Agency	Mary Ann Todd		Abstain	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Comments Submitted
4	Western Power Pool	Kevin Conway		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.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Abstain	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	Calpine Corporation	Whitney Wallace		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Dominion - Dominion Resources, Inc.	Anna Salmon		Negative	Comments Submitted
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Abstain	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Grid Strategies LLC	Michael Goggin		Negative	Comments Submitted
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Muscatine Power and Water	Chance Back		Negative	Comments Submitted
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		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	Northern California Power Agency	Jeremy Lawson		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NRG - NRG Energy, Inc.	Patricia Lynch		Abstain	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		None	N/A
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		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
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	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Tacoma Public Utilities (Tacoma, WA)	Ozan Ferrin	Jennie Wike	Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		None	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.	Michelle Hribar		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Comments Submitted
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted

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6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres		Abstain	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		None	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.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Platte River Power Authority	Sabrina Martz		Abstain	N/A
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Anne Kronshage		Negative	Comments Submitted
6	Puget Sound Energy, Inc.	Heather Pierce		Negative	Comments Submitted
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seattle City Light	Daren Brubaker		None	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville	Kimberly Bentley	Negative	Comments Submitted
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Lindsey Mannion		None	N/A
10	ReliabilityFirst	Tyler Schwendiman	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 298 of 298 entries

BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 AB 2 ST
Voting Start Date: 6/11/2024 12:01:00 AM
Voting End Date: 6/24/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 217
Total Ballot Pool: 265
Quorum: 81.89
Quorum Established Date: 6/21/2024 10:12:33 AM
Weighted Segment Value: 17.19

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	1	0.023	42	0.977	1	17	14
Segment: 2	8	0.8	4	0.4	4	0.4	0	0	0
Segment: 3	58	1	0	0	39	1	1	8	10
Segment: 4	9	0.5	0	0	5	0.5	0	2	2
Segment: 5	63	1	4	0.103	35	0.897	0	8	16
Segment: 6	44	1	3	0.088	31	0.912	0	4	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0.1	0	0	1	0.1	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.5	4	0.4	1	0.1	0	2	0
Totals:	265	5.9	16	1.014	158	4.886	2	41	48

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Third-Party Comments
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		None	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		None	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Third-Party Comments
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Third-Party Comments
1	Eversource Energy	Joshua London		Negative	Third-Party Comments
1	Exelon	Daniel Gacek		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	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	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Negative	Third-Party Comments
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	None	N/A
1	Orlando Utilities Commission	Aaron Staley		Negative	No Comment Submitted
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	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Third-Party Comments
1	Portland General Electric Co.	Brooke Jockin		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Negative	Third-Party Comments
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Third-Party Comments
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		None	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Third-Party Comments
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Third-Party Comments
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	Comments Submitted
2	New York Independent System Operator	Gregory Campoli		Negative	Third-Party Comments
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Negative	Third-Party Comments
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Third-Party Comments
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Avista - Avista Corporation	Robert Follini		Negative	Third-Party Comments
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	Dominion - Dominion Virginia Power	Victoria Crider		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Third-Party Comments
3	Eversource Energy	Vicki O'Leary		Negative	Third-Party Comments
3	Exelon	Kinte Whitehead		Abstain	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	Negative	Third-Party Comments
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Negative	Third-Party Comments
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments
3	New York Power Authority	Richard Machado		Negative	Third-Party Comments
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Orlando Utilities Commission	Ballard Mutters		Negative	No Comment Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Third-Party Comments
3	Portland General Electric Co.	Mayra Franco		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Third-Party Comments
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Third-Party Comments
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Third-Party Comments
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	Calpine Corporation	Whitney Wallace		None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Third-Party Comments
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Third-Party Comments
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
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	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Third-Party Comments
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	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		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PSEG Nuclear LLC	Tim Kucey		Negative	Third-Party Comments
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Third-Party Comments
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Third-Party Comments
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Third-Party Comments
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Third-Party Comments
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Third-Party Comments
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres		Abstain	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Manitoba Hydro	Brandin Stoesz		Negative	Third-Party Comments
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.	Dmitriy Bazylyuk		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Third-Party Comments
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Third-Party Comments
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Third-Party Comments
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Third-Party Comments
6	Western Area Power Administration	Jennifer Neville	Kimberly Bentley	Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Abstain	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	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		Negative	Comments Submitted

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BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources Implementation Plan AB 2 OT
Voting Start Date: 6/11/2024 12:01:00 AM
Voting End Date: 6/24/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 210
Total Ballot Pool: 257
Quorum: 81.71
Quorum Established Date: 6/21/2024 10:01:40 AM
Weighted Segment Value: 19.04

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	3	0.071	39	0.929	0	18	15
Segment: 2	8	0.8	3	0.3	5	0.5	0	0	0
Segment: 3	54	1	1	0.029	34	0.971	1	10	8
Segment: 4	9	0.5	0	0	5	0.5	0	2	2
Segment: 5	59	1	4	0.118	30	0.882	0	9	16
Segment: 6	44	1	4	0.125	28	0.875	0	6	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0.1	0	0	1	0.1	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	257	6	20	1.143	143	4.857	1	46	47

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Third-Party Comments
1	Ameren - Ameren Services	Tamara Evey		Negative	Third-Party Comments
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Third-Party Comments
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Third-Party Comments
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Third-Party Comments
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		None	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Third-Party Comments
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		None	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Third-Party Comments
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Third-Party Comments
1	Eversource Energy	Joshua London		Negative	Third-Party Comments
1	Exelon	Daniel Gacek		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Third-Party Comments
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	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	Third-Party Comments
1	Lakeland Electric	Larry Watt		Negative	Third-Party Comments
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Third-Party Comments
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		None	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Negative	Third-Party Comments
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Third-Party Comments
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker	Broc Bruton	None	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	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Third-Party Comments
1	Portland General Electric Co.	Brooke Jockin		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Negative	Third-Party Comments
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Third-Party Comments
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Third-Party Comments
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Third-Party Comments
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		None	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Third-Party Comments
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Third-Party Comments
2	Independent Electricity System Operator	Helen Lainis		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)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Third-Party Comments
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Avista - Avista Corporation	Robert Follini		Negative	Third-Party Comments
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Third-Party Comments
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Third-Party Comments
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Third-Party Comments
3	Dominion - Dominion Virginia Power	Victoria Crider		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Third-Party Comments
3	Eversource Energy	Vicki O'Leary		Negative	Third-Party Comments
3	Exelon	Kinte Whitehead		Abstain	N/A
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Negative	Third-Party Comments
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Lincoln Electric System	Sam Christensen		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	New York Power Authority	Richard Machado		Negative	Third-Party Comments
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	Orlando Utilities Commission	Ballard Mutters		Negative	No Comment Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Third-Party Comments
3	Portland General Electric Co.	Mayra Franco		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Negative	Third-Party Comments
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Third-Party Comments
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Third-Party Comments
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Third-Party Comments
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	WEC Energy Group, Inc.	Christine Kane		Negative	Third-Party Comments
3	Xcel Energy, Inc.	Nicholas Friebel		Negative	Third-Party Comments
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Third-Party Comments
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Third-Party Comments
4	WEC Energy Group, Inc.	Matthew Beilfuss		Negative	Third-Party Comments
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Third-Party Comments
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Third-Party Comments
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	Calpine Corporation	Whitney Wallace		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Third-Party Comments
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Third-Party Comments
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	JEA	John Babik		Negative	Third-Party Comments
5	Lincoln Electric System	Brittany Millard		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Negative	Third-Party Comments
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Third-Party Comments
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	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		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		None	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Negative	Third-Party Comments
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Third-Party Comments
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Third-Party Comments
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Third-Party Comments
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Third-Party Comments
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Third-Party Comments
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Third-Party Comments
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Third-Party Comments
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Third-Party Comments
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Third-Party Comments
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Third-Party Comments
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Third-Party Comments
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres		Abstain	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		None	N/A
6	Manitoba Hydro	Brandin Stoesz		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Third-Party Comments
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Third-Party Comments
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Third-Party Comments
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Third-Party Comments
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Third-Party Comments
6	Western Area Power Administration	Jennifer Neville	Kimberly Bentley	Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	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		Negative	Comments Submitted

BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 | Non-binding Poll AB 2 NB
Voting Start Date: 6/11/2024 12:01:00 AM
Voting End Date: 6/24/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 195
Total Ballot Pool: 246
Quorum: 79.27
Quorum Established Date: 6/24/2024 9:28:46 AM
Weighted Segment Value: 10.37

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	72	1	1	0.029	33	0.971	23	15
Segment: 2	7	0.5	2	0.2	3	0.3	2	0
Segment: 3	53	1	0	0	31	1	13	9
Segment: 4	9	0.5	0	0	5	0.5	2	2
Segment: 5	56	1	3	0.107	25	0.893	11	17
Segment: 6	41	1	3	0.115	23	0.885	7	8
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0.1	0	0	1	0.1	0	0
Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	7	0.5	5	0.5	0	0	2	0
Totals:	246	5.6	14	0.952	121	4.648	60	51

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		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Austin Energy	Thomas Standifur		Abstain	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Abstain	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		None	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Negative	Comments Submitted
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Dominion - Dominion Virginia Power	Elizabeth Weber		Negative	Comments Submitted
1	Duke Energy	Katherine Street		None	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Negative	Comments Submitted
1	Entergy	Brian Lindsey		None	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Abstain	N/A
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Negative	Comments Submitted
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Negative	Comments Submitted
1	Lincoln Electric System	Josh Johnson		None	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		Negative	Comments Submitted
1	Minnkota Power Cooperative Inc.	Theresa Allard		Abstain	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		None	N/A
1	Oncor Electric Delivery	Byron Booker		None	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	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		None	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		None	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		None	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Negative	Comments Submitted
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	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		Negative	Comments Submitted
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		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	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	Colorado Springs Utilities	Hillary Dobson		None	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Negative	Comments Submitted
3	Dominion - Dominion Virginia Power	Victoria Crider		None	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Edison International - Southern California Edison Company	Romel Aquino		None	N/A
3	Entergy	James Keele		None	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Abstain	N/A
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		Negative	Comments Submitted
3	Lincoln Electric System	Sam Christensen		None	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted
3	National Grid USA	Brian Shanahan		Abstain	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	Richard Machado		Negative	Comments Submitted
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Abstain	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Negative	Comments Submitted
3	Orlando Utilities Commission	Ballard Mutters		Negative	Comments Submitted
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	Portland General Electric Co.	Mayra Franco		None	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Negative	Comments Submitted
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Abstain	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	DTE Energy	Patricia Ireland		Abstain	N/A
4	Northern California Power Agency	Marty Hostler		None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Abstain	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
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.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Calpine Corporation	Whitney Wallace		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		None	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		None	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Muscatine Power and Water	Chance Back		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NextEra Energy	Richard Vendetti		Abstain	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Affirmative	N/A
5	Orlando Utilities Commission	Dania Colon		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		None	N/A
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 Snohomish County	Becky Burden		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Nikkee Hebdon		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Abstain	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Negative	Comments Submitted
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Negative	Comments Submitted
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Edison International - Southern California Edison Company	Stephanie Kenny		Negative	Comments Submitted
6	Entergy	Julie Hall		None	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	N/A
6	Imperial Irrigation District	Diana Torres		Abstain	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		None	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.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
6	Omaha Public Power District	Shonda McCain		Negative	Comments Submitted
6	Portland General Electric Co.	Stefanie Burke		None	N/A
6	Powerex Corporation	Raj Hundal		Negative	Comments Submitted
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		Negative	Comments Submitted
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Abstain	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville	Kimberly Bentley	Negative	Comments Submitted
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Negative	Comments Submitted
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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

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Standard Development Timeline

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

Description of Current Draft

This is the 45-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 19 – November 4, 2024
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 13, 2024

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

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

Term(s):

The term Near-Term Energy Reliability Assessment refers to the proposed definition being developed under the Project 2022-03 Energy Assurance. As of this posting, the proposed definition of Near-Term Energy Reliability Assessment is:

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection

2. **Number:** TOP-003-7

3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.

4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider

5. **Effective Date:** See Implementation Plan for Project 2022-03.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, and Energy Reliability Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes at a minimum the following.

1.5.1. Specified deadlines or periodicity which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Provisions to update or correct data and information, as applicable or necessary;

1.5.4. A mutually agreeable format;

1.5.5. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following.

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Provisions to update or correct data and information, as applicable or necessary.

2.5.4. A mutually agreeable format.

2.5.5. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real- time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

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

4.1.2 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.

Each responsible 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 shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

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

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
For the Requirement R3 and R4 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	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to three entities, or more than10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet one of the parts in	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet two of the parts in	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet three or more of the parts in Requirement R1 Part 1.5 or	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Requirement R1 Part1.5 or Requirement R2 Part 2.5.	Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	Requirement R2 Part 2.5.	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

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		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP- 003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23,2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No.RD23-6-000,	

6.1	November 3, 2023	Effective Date	July 1, 2025
7	TBD	Energy Assurance Modifications – Addition of Near-Term ERA.	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 45-day formal comment period with initial ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022

Anticipated Actions	Date
45-day formal comment period with initial ballot	September 19 – November 4, 2024
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 13, 2024

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

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

Term(s):

The term Near-Term Energy Reliability Assessment refers to the proposed definition being developed under the Project 2022-03 Energy Assurance. As of this posting, the proposed definition of Near-Term Energy Reliability Assessment is:

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection
2. **Number:** TOP-003-7~~6.1~~
3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.
4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider
5. **Effective Date:** See Implementation Plan for Project ~~2021-06~~2022-03.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments, and Energy Reliability Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes at a minimum the following.

1.5.1. Specified deadlines or periodicity which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Provisions to update or correct data and information, as applicable or necessary;

1.5.4. A mutually agreeable format;

1.5.5. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions and Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following.

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Provisions to update or correct data and information, as applicable or necessary.

2.5.4. A mutually agreeable format.

2.5.5. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real- time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

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

4.1.2 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.

Each responsible 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 shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions and Real-time monitoring in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.

Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions and Real-time monitoring in accordance with Requirement R4 and Measurement M4.

Each Balancing Authority, Generator Owner, Generator Operator, Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

4.1.3 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	~~Operations Planning~~	~~Lower~~	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real- time Assessments.
R2	~~Operations Planning~~	~~Lower~~	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, ~~and~~ Real- time monitoring, and	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, ~~and~~ Real- time	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, ~~and~~ Real- time monitoring,	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, ~~and~~ Real- time monitoring, and

R#	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			Near-Term Energy Reliability Assessments.	monitoring, and Near-Term Energy Reliability Assessments.	and Near-Term Energy Reliability Assessments.	Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions, ~~and~~ Real- time monitoring, and Near-Term Energy Reliability Assessments.
For the Requirement R3 and R4 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~~	~~Lower~~	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	~~Operations Planning~~	~~Lower~~	The Balancing Authority did not distribute its Specification(s) to one	The Balancing Authority did not distribute its Specification(s) to two	The Balancing Authority did not distribute its Specification(s) to three	The Balancing Authority did not distribute its Specification(s) to four or

R#	~~Time Horizon~~	~~VRF~~	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments.	entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments.	entities, or more than10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments.	more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, ~~and~~ Real-time monitoring, and Near-Term Energy Reliability Assessments.
R5	~~Operations Planning, Same-Day Operations, Real-time Operations~~	~~Medium~~	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations in the specification but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

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		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP- 003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23,2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No.RD23-6-000,	

6.1	November 3, 2023	Effective Date	July 1, 2025
7	TBD	Energy Assurance Modifications – Addition of Near-Term ERA.	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

Draft 3 of BAL-007-1 is posted for a 45-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024
45-day formal comment period with additional ballot	May 7 – June 20, 2024

Anticipated Actions	Date
45-day formal or informal comment period with additional ballot	September 19 – November 4, 2024
10-day final ballot	December 2 – 11, 2024
Board adoption	December 13, 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Near-term Energy Reliability Assessments
2. **Number:** BAL-007-1
3. **Purpose:** To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
5. **Effective Date:** See Implementation Plan for BAL-007-1.

B. Requirements and Measures

R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a process for conducting Near-Term Energy Reliability Assessments (ERA). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The Near-Term ERA process shall account for:

1.1.1. Forecasted or assumed Demand profiles;

1.1.2. Resource capabilities and operational limitations, including fuel supply;

1.1.3. Energy transfers with other Balancing Authorities; and

1.1.4. Known Bulk Electric System (BES) Transmission constraints that limit the ability of generation to deliver their output to Load.

1.2. The Near-Term ERA process shall specify the duration of the Balancing Authority's Near-Term ERAs.

1.3. The Near-Term ERA process shall specify the frequency at which the Balancing Authority will conduct Near-Term ERAs, subject to the following:

1.3.1. Each Balancing Authority will conduct Near-Term ERAs for all time periods unless the Balancing Authority demonstrates, via a documented methodology, that a Near-Term ERA is not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s).

1.3.2. The documented methodology for identifying time periods for which the Balancing Authority will not conduct a Near-Term ERA must (i) define the criteria used to determine when there is a low risk of an Energy Emergency occurring, and (ii) account for the items listed in 1.1.1 – 1.1.4 and other conditions associated with Energy Emergencies.

M1. Each Balancing Authority shall have evidence that it documented a process for conducting Near-Term ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a set of Scenarios, or a method for developing Scenarios, for use in performing Near-Term ERAs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. The set of Scenarios must include (i) a base Scenario with expected system conditions, and (ii) other Scenarios that stress the system due to the following conditions, as applicable to the Balancing Authority's system:

2.1.1. Higher than forecasted or assumed Demand profiles;

2.1.2. The effects of an energy supply contingency;

2.1.3. The effects of a fuel supply contingency; and

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the best information available at the time of Scenario development.

M2. Each Balancing Authority shall document the rationale for the Scenarios, or the method of developing Scenarios, for use in performing Near-Term ERAs.

R3. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document one or more Operating Plan(s) to implement in response to forecasted Energy Emergencies, including provisions for notification to their Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it documented its Operating Plan(s) in accordance with Requirement R3.

R4. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, perform Near-Term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall have evidence that it performed the Near-Term ERAs in accordance with Requirement R4.

R5. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, implement its Operating Plan(s), as documented in Requirement R3, when Near-Term ERAs identify any of the following forecasted Energy Emergencies: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B; or
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B.

M5. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) in accordance with Requirement R5.

R6. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, review, update, as necessary, and provide to the applicable Reliability Coordinator its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3, at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have evidence that it reviewed and documented its Near-term ERA process, Scenarios or methods, and Operating Plan(s) to its Reliability Coordinator, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Balancing Authority shall keep data or evidence to show compliance with applicable requirements for six months for Near-Term ERAs or since the last audit.

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 Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 or Part 1.2.	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 through Part 1.2. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for one of the elements in Requirement R1 Part 1.3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.
R2.	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include one of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include two of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include three of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include any of the conditions listed in Requirement R2 Part 2.1. OR The Balancing Authority failed to document a set of Scenarios or a method of Scenario

				creation for use in performing Near-Term ERAs.
R3.	N/A	N/A	The Balancing Authority documented an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs.
R4.	N/A	N/A	N/A	The Balancing Authority failed to perform a Near-Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.
R5.	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a Near-Term ERA identified any of the forecasted conditions in Requirement R5.
R6.	N/A	N/A	The Balancing Authority reviewed information that contained the Near-Term ERAs process, the ERA Scenarios or methods, and Operating	The Balancing Authority failed to review and update information that contained the Near-Term ERAs process, the ERA Scenarios or methods,

			Plan(s) but failed to update within 24 months.	and Operating Plan(s) to the Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan
- NERC Project 2022-03 Technical Rationale
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
1	TBD	NERC Project 2022-03 energy assurance new standard.	New

Standard Development Timeline

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

Description of Current Draft

Draft 3 of BAL-007-1 is posted for a 45-day formal comment period with additional ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024
45-day formal comment period with additional ballot	May 7 – June 20, 2024

Anticipated Actions	Date
45-day formal or informal comment period with additional ballot	September 19 – November 4, 2024
10-day final ballot	December 2 – 11, 2024
Board adoption	December 13, 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) – ~~Evaluation~~Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated ~~evaluation~~assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Near-term Energy Reliability Assessments

2. **Number:** BAL-007-1

3. **Purpose:** To ~~the risks associated with~~assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon. ~~time horizon and take appropriate actions to address identified risk. As the Bulk-Power System becomes more reliant upon energy-constrained and variable resources, traditional capacity-based planning methods and strategies might not identify energy-related risks to reliable System operation.~~

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1. Balancing Authority

   ~~**4.1.2.** Reliability Coordinator~~

5. **Effective Date:** See Implementation Plan for BAL-007-1.

B. Requirements and Measures

R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document ~~and maintain~~ a process for conducting Near-Term Energy Reliability Assessments (ERA)~~) for the near-term time horizon.~~). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~**1.1.**~~ The ~~near-term ERA must have a duration between five days and six weeks and begin no later than two days after the present operating day.~~

~~**1.2.** The frequency of near-term ERA must be at intervals that ensure all time periods are covered by a near-term ERA.~~

~~**1.3.**~~**1.1.** ~~The~~Near-Term ERA process ~~for near-term ERAs must~~shall account for~~ the following~~:

~~**1.3.1.**~~**1.1.1.** Forecasted or assumed Demand profiles;

1.1.2. Resource capabilities and ~~operations~~operational limitations, including ~~depletion of~~ fuel~~, variable energy resources (e.g., wind, solar, and hydro), energy~~ supply;

~~**1.3.2.**~~**1.1.3.** Energy transfers ~~between neighboring~~with other Balancing Authorities~~, and electric storage~~; and

~~**1.3.3.**~~**1.1.4.** Known Bulk Electric System (BES) Transmission constraints that limit the ability of generation to deliver their output to ~~load~~Load.

1.2. The Near-Term ERA process ~~for near-term ERAs~~ shall ~~include~~specify the ~~rationale for each~~duration of the ~~elements~~Balancing Authority's Near-Term ERAs.

1.3. The Near-Term ERA process shall specify the frequency at which the Balancing Authority will conduct Near-Term ERAs, subject to the following:

1.3.1. Each Balancing Authority will conduct Near-Term ERAs for all time periods unless the Balancing Authority demonstrates, via a documented methodology, that a Near-Term ERA is not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s).

~~**1.3.4.**~~**1.3.2.** The documented methodology for identifying time periods for which the Balancing Authority will not conduct a Near-Term ERA must (i) define the criteria used to determine when there is a low risk of an Energy Emergency occurring, and (ii) account for the items listed in ~~Parts 1.1 through 1.3~~1.1.1 – 1.1.4 and other conditions associated with Energy Emergencies.

M1. Each Balancing Authority shall have evidence that it documented ~~and maintained~~ a process for conducting ~~near-term~~Near-Term ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document ~~and maintain~~ a set of Scenarios, or a method ~~of Scenario creation~~for developing Scenarios, for use in performing ~~near-term ERAs. Each Scenario or method shall vary one or more of the following conditions by a sufficient amount to stress the system within a range of credible situations. Include a rationale for the Scenarios or method identified.~~Near-Term ERAs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. ~~Forecasted~~The set of Scenarios must include (i) a base Scenario with expected system conditions, and (ii) other Scenarios that stress the system due to the following conditions, as applicable to the Balancing Authority's system:

2.1.1. Higher than forecasted or assumed Demand profiles~~.~~;

~~**2.2.** Resource capabilities and operations, including the following:~~

~~**2.2.1.**~~**2.1.2.** The effects of ~~a credible~~an energy supply contingency;

~~**2.2.2.**~~**2.1.3.** The effects of a ~~credible~~ fuel supply contingency; and

~~**2.2.3.** Unplanned generator outages.~~

~~**2.2.4.**~~**2.1.4.** Other ~~Scenarios with a credible or~~stressed conditions that have a historical ~~risk~~precedent of occurring, as defined by the Balancing Authority, based on the best information available at the time of Scenario ~~creation~~development.

~~**M2.** Each Balancing Authority shall have evidence that Scenarios or methods were developed and maintained along with a documented rationale in accordance with Requirement R2.~~

M2. Each Balancing Authority shall document ~~and maintain~~the rationale for the Scenarios, or the method of developing Scenarios, for use in performing Near-Term ERAs.

R3. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document one or more Operating Plan(s) to ~~minimize forecasted Energy Emergencies as identified~~implement in ~~the near-term ERA~~response to forecasted Energy Emergencies, including provisions for ~~notifying the~~notification to their Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it documented ~~and maintained~~ its Operating Plan(s) in accordance with Requirement R3.

~~**M4.** The Balancing Authority shall review and update, if necessary, its near-term ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 at least once every 24 calendar months.~~ Each Balancing Authority shall ~~have evidence that it reviewed and updated, if necessary, its near-term~~

~~ERA process, Scenarios or methods, and Operating Plan(s), in accordance with Requirement R4.~~

~~**R4.** Each Balancing Authority shall provide its near-term ERA process, Scenarios or methods, and Operating Plan(s) documented under Requirements R1 through R3 to the Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M5.** Each Balancing Authority shall have evidence it provided its near-term ERA process, Scenarios, or methods, and Operating Plan(s) documented under Requirement R1 through R3 to its Reliability Coordinator at least once every 24 calendar months, on a mutually agreed schedule, in accordance with Requirement R5.~~

~~**R5.** Within 60 calendar days of receipt of the information identified in Requirement R5, the Reliability Coordinator shall: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**5.1.** Review each submittal for coordination~~, individually or jointly with other Balancing ~~Authorities' ERA information to avoid risks to Wide Area reliability; and~~

~~**5.2.** Notify each Balancing Authority of the results of its review and if revisions are needed to address reliability risks.~~

~~**M6.** Each Reliability Coordinator shall have evidence that it reviewed each submittal and notified each Balancing Authority of the results of the review in accordance with Requirement R6.~~

~~**R6.** Within 60 calendar days of receipt of the Reliability Coordinator's notice under Requirement R6, each Balancing Authority shall address any reliability risks identified by its Reliability Coordinator and resubmit the updated information required in Requirement R4 to its Reliability Coordinator. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~**M7.** Each Balancing Authority shall have evidence that it addressed any reliability risks identified by its Reliability Coordinator and resubmitted updated information to its Reliability Coordinator in accordance with Requirement R7.~~

~~R7.~~R4. ~~Each Balancing Authority shall~~Authorities, perform ~~near-term~~Near-Term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

~~M8.~~M4. Each Balancing Authority shall have evidence that it performed the ~~near-term ERA~~Near-Term ERAs in accordance with Requirement ~~R8.~~R4.

~~R8.~~R5. ~~If a near-term ERA identifies any of the following forecasted Energy Emergencies listed below, the~~Each Balancing Authority shall, individually or jointly with other

Balancing Authorities, implement ~~an~~its Operating Plan(s), as documented in Requirement R3~~.~~, when Near-Term ERAs identify any of the following forecasted Energy Emergencies: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- ~~Forecasted EEA1 circumstances as defined in EOP-011 Attachment 1 Section B~~
- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B; or
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B.

~~M9.~~M5. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) in accordance with Requirement ~~R9~~R5.

~~R9.~~R6. Each ~~Reliability Coordinator, within 24 hours of receiving a notification that a~~ Balancing Authority ~~within its footprint has implemented an Operating Plan pursuant to Requirement R8,~~ shall ~~notify~~ , individually or jointly with other Balancing Authorities, review, update, as necessary, and ~~Transmission Operators in its~~ provide to the applicable Reliability Coordinator ~~Area~~its Near-term ERA process, Scenarios or methods, and ~~neighboring Reliability Coordinators of the forecasted condition~~Operating Plan(s), documented under Requirements R1 through R3, at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

~~R10.~~ ~~and the~~Each Balancing ~~Authority's Operating Plan(s).~~ ~~*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~M10.~~M6. ~~Each Reliability Coordinator~~Authority shall have evidence ~~demonstrating~~ that it ~~communicated, within 24 hours from the time of receiving notice of implementation of a Balancing Authority's Operating Plan, with the other Balancing Authorities~~reviewed and documented its Near-term ERA process, Scenarios or methods, and ~~Transmission Operators in~~Operating Plan(s) to its Reliability Coordinator ~~area, and neighboring Reliability Coordinators~~, in accordance with Requirement ~~R10~~R6.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Balancing Authority ~~and Reliability Coordinator~~ shall keep data or evidence to show compliance with applicable requirements for six months for ~~near-term time horizon~~Near-Term ERAs or since the last audit.

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 Balancing Authority documented an Energy Reliability Assessment process for the ~~near-term time horizon~~Near-Term ERAs but did not account for ~~one of~~ the elements in Requirement R1 Part 1.1 ~~through~~or Part 1.~~3~~2. ~~OR~~ ~~The Balancing Authority documented a Reliability Coordinator-reviewed Energy Reliability Assessment process for the near-term time horizon accounting for each of the elements in Requirement R1 Parts 1.1 through 1.3 but failed to maintain it.~~	The Balancing Authority documented an Energy Reliability Assessment process for the ~~near-term time horizon~~Near-Term ERAs but did not account for ~~two or more of~~ the elements in Requirement R1 Part 1.1 through Part 1.~~3~~2. OR The Balancing Authority documented an Energy Reliability Assessment process for the ~~near-term time horizon~~Near-Term ERAs but did not ~~provide a rationale~~account for one of the elements in ~~accordance with~~ Requirement R1 Part 1.~~4.~~ 3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the ~~near-term time horizon~~Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.
R2.	~~N/A~~The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include one of the conditions listed in Requirement R2 Part 2.1.	~~The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not maintain it.~~ ~~OR~~	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not ~~vary conditions by a sufficient amount to stress the system or~~	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include any of the conditions listed in Requirement R2 Part 2.1.

		The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include ~~a rationale for the Scenarios or method identified.~~two of the conditions listed in Requirement R2 Part 2.1.	~~include all~~include three of the conditions listed in Requirement R2 ~~Parts~~Part 2.1 ~~through 2.3~~.	OR The Balancing Authority failed to document a set of Scenarios or a method of Scenario creation for use in performing ~~near-term~~Near-Term ERAs.
R3.	N/A	N/A	The Balancing Authority documented ~~and maintained~~ an Operating Plan(s) to ~~minimize~~implement in response to forecasted Energy Emergencies as identified in the ~~near-term ERA~~Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to ~~minimize~~implement in response to forecasted Energy Emergencies as identified in the ~~near-term ERA~~Near-Term ERAs.
~~**R4.**~~	~~N/A~~	~~N/A~~	~~The Balancing Authority reviewed information that contained the near-term ERA process, the ERA scenarios or methods, and Operating Plan(s) but failed to update within 24 months.~~	~~The Balancing Authority failed to review and update, if necessary, information that contained the near-term ERA process, the ERA scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.~~
~~**R5.**~~	~~N/A~~	~~N/A~~	~~The Balancing Authority submitted information that contained the near-term ERA~~	~~The Balancing Authority failed to submit information that contained the near-term ERA~~

			~~process, the ERA scenarios, and Operating Plan(s) but failed to submit to the Reliability Coordinator within 24 months, on a mutually agreed-upon schedule.~~	~~process, the ERA scenarios, and Operating Plan(s) to the Reliability Coordinator.~~
~~R6.~~	~~N/A~~	~~The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but notified one or more Balancing Authority of the results of its review in a time period that was longer than 60 calendar days but less than 90 calendar days.~~	~~The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but notified one or more Balancing Authority of the results of its review in a time period that was longer than 90 calendar days but less than 120 calendar days.~~	~~The Reliability Coordinator reviewed each submittal for coordination with other Balancing Authorities' near-term ERA information to understand potential reliability risks to Wide Area reliability but failed to notify each Balancing Authority of the results of its review within 120 calendar days.~~
~~R7.~~	~~N/A~~	~~N/A~~	~~The Balancing Authority addressed any reliability risks identified by its Reliability Coordinator but failed to resubmit the updated information within 60 calendar days following receipt.~~	~~The Balancing Authority failed to address any reliability risks identified by its Reliability Coordinator.~~ ~~OR~~ ~~The Balancing Authority failed to resubmit the updated information required in Requirement R4 to its Reliability Coordinator.~~
~~R8.~~ R4.	N/A	N/A	N/A	The Balancing Authority failed to perform a ~~near-term~~Near-

				Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.
~~R9.~~ R5.	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a ~~near-term~~Near-Term ERA identified any of the forecasted conditions in Requirement ~~R8~~R5.
~~R10.~~R6.	~~The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R9 but notified one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 24-25 hours of receiving notification.~~N/A	~~The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R9 but notified one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 25-26 hours of receiving notification.~~N/A	~~The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R9 but notified one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators between 26-27 hours of receiving notification.~~The Balancing Authority reviewed information that contained the Near-Term ERAs process, the ERA Scenarios or methods, and Operating Plan(s) but	~~The Reliability Coordinator received a notification that a Balancing Authority within its footprint has implemented an Operating Plan pursuant to Requirement R8 but failed to notify one or more Balancing Authorities or Transmission Operators in its Reliability Coordinator Area, or neighboring Reliability Coordinators within 27 hours or more of receiving notification.~~The Balancing Authority failed to review and update information that contained the Near-Term ERAs process, the ERA Scenarios or methods, and Operating

			failed to update within 24 months.	Plan(s) to the Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan
- NERC Project 2022-03 Technical Rationale
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
1	TBD	NERC Project 2022-03 energy assurance new standard.	New

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Implementation Plan

Project 2022-03 Energy Assurance with Energy-Constrained Resources | Reliability Standard BAL-007-1 and TOP-003-7

Applicable Standard(s)

- BAL-007-1 – Near-term Energy Reliability Assessments
- TOP-003-7 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement(s)

- TOP-003-6.1 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Transmission Operator
- Generator Owner
- Generator Operator
- Transmission Owner
- Distribution Provider

Terms in the NERC Glossary of Terms

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

Proposed New Definition(s):

Energy Reliability Assessment:	Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand

	and to provide Operating Reserves for the Bulk Power System throughout the associated Assessment period.
Near-Term Energy Reliability Assessment:	An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

Background

Energy assurance is an increasingly important aspect of a reliable Bulk-Power System (BPS) but has been inconsistently defined and measured without explicit standards. Project 2022-03 Energy Assurance with Energy-Constrained Resources was initiated to address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Reliability Standard BAL-007-1 – Energy Reliability Assessments is focused on the operations planning time horizon.

BAL-007-1 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard BAL-007-1 shall become effective on the first day of the first calendar quarter that is 24 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 24 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definitions

Where approval by an applicable governmental authority is required, the definitions of Energy Reliability Assessment and Near-term Energy Reliability Assessment shall become effective on the first day of the first calendar quarter that is 24 months after the effective date of the applicable governmental authority's order approving Reliability Standard BAL-007-1, 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 24 months after the date that Reliability Standard BAL-007-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-003-7 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard TOP-003-7 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.

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Implementation Plan

Project 2022-03 Energy Assurance with Energy-Constrained Resources | Reliability Standard BAL-007-1 and TOP-003-7

Applicable Standard(s)

- BAL-007-1 – Near-term Energy Reliability Assessments
- TOP-003-7 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement(s)

- ~~None~~
- TOP-003-6.1 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard(s)

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- ~~Reliability Coordinator~~
- Transmission Operator
- Generator Owner
- Generator Operator
- Transmission Owner
- Distribution Provider

Terms in the NERC Glossary of Terms

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

Proposed New Definition(s):

Energy Reliability Assessment:	~~Evaluation~~Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated ~~evaluation~~Assessment period.
Near-Term Energy Reliability Assessment:	An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

Background

Energy assurance is an increasingly important aspect of a reliable Bulk-Power System (BPS) but has been inconsistently defined and measured without explicit standards. Project 2022-03 Energy Assurance with Energy-Constrained Resources was initiated to address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Reliability Standard BAL-007-1 – Energy Reliability Assessments is focused on the operations planning time horizon.

~~Effective Date and Phased-In Compliance Dates~~

~~The effective dates for proposed Reliability Standard BAL-007-1 and NERC Glossary term Energy Reliability Assessment 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.~~

BAL-007-1 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard BAL-007-1 shall become effective on the first day of the first calendar quarter that is ~~18~~24 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~~24 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

~~Phased-In Compliance Dates~~

~~Compliance Date for BAL-007-1 Requirements R1, R2, and R3~~

~~Entities shall not be required to comply with Requirements R1 – R3 until 18 months after the effective date of Reliability Standard BAL-007-1.~~

~~Compliance Date for BAL-007-1 Requirements R4 and R5~~

~~Initial Balancing Authority review of its near-term Energy Reliability Assessments process, Scenarios or methods, and Operating Plan(s) is due by the effective date, subsequent reviews due no later than 24 months following the effective date.~~

~~Initial Balancing Authority submission to Reliability Coordinator is due by the effective date, subsequent reviews due no later than 24 months following the effective date on a mutually agreed upon schedule.~~

~~Periodic reviews and submissions are due no later than 24 months following the effective date.~~

~~**Compliance Date for BAL-007-1 Requirements R6, R7, R8, R9, and R10**~~
~~Entities shall not be required to comply with Requirements R6 – R10 until 24 months after the effective date of Reliability Standard BAL-007-1.~~

~~Definition~~Definitions
Where approval by an applicable governmental authority is required, the ~~definition of~~definitions of Energy Reliability Assessment and Near-term Energy Reliability Assessment shall become effective on the first day of the first calendar quarter that is ~~18~~24 months after the effective date of the applicable governmental authority's order approving Reliability Standard BAL-007-1, 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~~24 months after the date that Reliability Standard BAL-007-1 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-003-7 Reliability Standard
Where approval by an applicable governmental authority is required, Reliability Standard TOP-003-7 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.

Unofficial Comment Form

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on draft three of **BAL-007-1 – Near-term Energy Reliability Assessments** and draft one of **TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection** by **8 p.m. Eastern, Monday, November 4, 2024.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Jordan Mallory (via email).

Background Information

Project 2022-03 currently is addressing the operations/operational planning time horizon Standard Authorization Requests (SARs) that seek to enhance reliability by requiring entities to perform Energy Reliability Assessments (ERAs) to evaluate energy assurance and develop Corrective Action Plan(s), Operating Plan(s), or other mitigating actions to address identified risks to each respective time horizon.

The Standards Committee (SC) accepted the revised SAR at its January 25, 2023, meeting. At the same meeting, the SC authorized drafting of the Reliability Standard(s) identified in the SAR. Since that time, the team has conducted several meetings, both remote and in-person, and posted a draft of a new standard for informal comment to solicit feedback and completed one initial comment and ballot period for BAL-007-1.

Summary of changes Overview

Based on industry feedback, the drafting team (DT) modified BAL-007-1 to remove redundant and administrative burden type requirements. The updated standard provides flexibility to industry when completing its Near-Term Energy Reliability Assessments. The team decided to focus its efforts on BAL-007-1 Near-Term ERAs and is holding off on BAL-008-1, which address seasonal ERAs. The team will discuss and determine the next steps regarding the Seasonal ERA standard following the completion of BAL-007-1. In addition to the updates of BAL-007-1, the DT worked to address concerns from industry that it is not clear that Near-Term ERA type data can be required through TOP-003-7. The DT modified TOP-003-7 to include the term “Near-Term ERA” within the TOP-003-7 standard to make this clear.

As a reminder, the proposed definition is not balloted separately but is being balloted via the BAL-007-1 standard. As such, when voting on the standard, ballot body participants will also be voting on the proposed definition used in the standard.

Questions

BAL-007-1 Near-term ERAs

1. The drafting team (DT) modified BAL-007-1 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No

   Comments:

2. The DT updated the implementation plan to allow for 24 months for BAL-007-1 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No

   Comments:

3. The DT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request 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:

4. Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

   Comments:

TOP-003-7

5. The drafting team (DT) modified TOP-003-6 to ensure industry that Near-Term ERA type data can be requested. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No

   Comments:

6. The DT drafted the TOP-003-7 implementation plan allowing 18 months to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

   ☐ Yes
   ☐ No

   Comments:

7. The DT proposes that the modified TOP-003-7 meets the Standards Authorization Request 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. Provide any TOP-003-7 additional comments for the SDT to consider, if desired.

   Comments:

Technical Rationale

Project 2022-03 Energy Assurance with Energy-Constrained Resources
Reliability Standard BAL-007-1 | September 2024

BAL-007-1– Near-term Energy Reliability Assessments

Introduction
This document explains the technical rationale and justification for the proposed Reliability Standard BAL-007-1. It provides stakeholders and the Electric Reliability Organization (ERO) Enterprise with an understanding of the technical requirements in the Reliability Standards. This Technical Rationale and Justification for BAL-007-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Updates to this document include the Project 2022-03 Energy Assurance with Energy-Constrained Resources Drafting Team's (DT's) intent in drafting new requirements.

Overview
Inconsistent output from variable energy resources, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the Bulk Power System (BPS) needed to serve electrical Demand, maintain sufficient Operating Reserve, and ensure the reliable operation of the BPS. As part of ongoing operations planning, many entities have started incorporating some limited studies of energy reliability assessments that produce key metrics; however, there is inconsistency among entities on how the assessments are performed. To achieve the level of consistency needed across the industry, to reliably predict the energy needed to serve the load, energy reliability assessments for the operations time horizon and the minimization of identified risks are mandated and codified in this new standard. Project 2022-03 proposes two new Reliability Standards, BAL-007-1 and the Energy Reliability Assessment (ERA) definition. The purpose of the proposed Reliability Standard BAL-007-1 is to identify and minimize the risks of forecasted Energy Emergencies in the operations planning time horizon by analyzing the expected resource mix availability.

Rationale for BAL-007-1
As the BPS becomes more reliant upon energy constrained and variable resources, traditional capacity-based planning methods and strategies are being stretched and potentially do not identify energy-related risks to reliably operate and maintain the system. BAL-007-1 is being proposed as a step toward reducing these potential risks and to begin the transition to energy-based planning methods and strategies that incorporate critical time-based variables that are not captured in capacity-based processes.

BAL-007-1 is intended to provide Balancing Authorities (BAs) with the tools necessary to successfully navigate a system that has both variable load and resources.

BAL-007-1 Operating Plan(s), which are not intended to replace or supersede TOP-002 and EOP-011 Operating Plans, are intended to provide a list of actions over a longer-term/earlier time period that can reduce the severity of or fully mitigate the need to implement TOP-002 and/or EOP-011 plans.

The new Reliability Standard can be separated into three basic activities:

- Developing and documenting an ERA process, Scenarios or a method for creating them, and Operating Plans (Requirements 1-3).
- Performing ERAs as documented (Requirement 4).
- Comparing to forecasted Energy Emergency conditions and, if identified, implementing Operating Plan(s) in response to energy reliability risks (Requirement 5).

The purpose of the standard is to assess energy risk in the Operations Planning time horizon, determine if the identified risks are acceptable, and take action when appropriate. It should be noted that the standard offers the flexibility to allow for either a deterministic or probabilistic implementation of an ERA process. This has been left up to the BA to determine which method is right for their region. This standard improves reliability through identifying energy risks earlier and being able to implement longer lead time activities to mitigate those risks.

Relationship to Other Standards

While the proposed standard has similarities to other standards, especially TOP-001, TOP-002, and EOP-011, the proposed standard addresses reliability risks due to gaps in the existing reliability standards by focusing on different time horizons than current standards and energy risks which are not clearly addressed. In many cases, the language is intentionally similar to language in those requirements but applicable to different time horizons. The BAL-007-1 standard looks at a near-term time horizon which is longer than other operations planning assessment requirements. In terms of addressing energy risks, BAL-007-1 more clearly outlines the assessment requirements to look at energy over an assessment period rather than capacity assessments generally used to comply with current standards.

TOP-001 and TOP-002 provide requirements for assessments and Operating Plans in real-time and operations planning time horizons, but their requirements are limited to, at most the next day, which limits the options that Balancing Authorities may take to respond. BAL-007-1's proposed language extends this outlook to at least greater than five days and up to six weeks ahead, so BAs have time to implement mitigation actions with longer lead times (e.g., reschedule outages, conserve consumable fuel, source additional fuel) and have better situational awareness of potential reliability risks.

TOP-002, EOP-011, and BAL-007-1 all require Operating Plans to minimize or mitigate reliability risks, but they would likely differ in what actions that a BA would deem appropriate to be included in each. Since BAL-007-1 is assessing a longer time horizon, the projected conditions are more uncertain, and the Operating Plans developed should reflect that. Instead of identifying specific actions that must be taken, the Operating Plans under BAL-007-1 are expected to have more general processes than Operating Plans in TOP-002. BAL-007-1 Operating Plans are not intended to replace TOP-002 and EOP-011 Operating Plans but to identify

additional actions that can be implemented when potential risks are identified with a longer lead time and with an energy component of the assessment. The goal of these longer-term Operating Plans is to reduce the likelihood, or the severity of, an actual Energy Emergency occurring, which would require an EOP-011 Operating Plan. Actions that are taken as outlined in the BAL-007-1 Operating Plans would then lead into the day-ahead Operating Plans and real time, through the establishment of more favorable initial conditions, rather than overlapping them. An example timeline of how BAL-007-1 and EOP-011 would interact is shown below in *Figure 1* when the TOP-002 associated Operating Plans are not sufficient to avoid an Energy Emergency. Ideally, the longer-term Operating Plan(s) would result in the EOP-011 Operating Plan not being needed but if an Energy Emergency still occurs, the Operating Plans should have reduced the severity of the Energy Emergency.

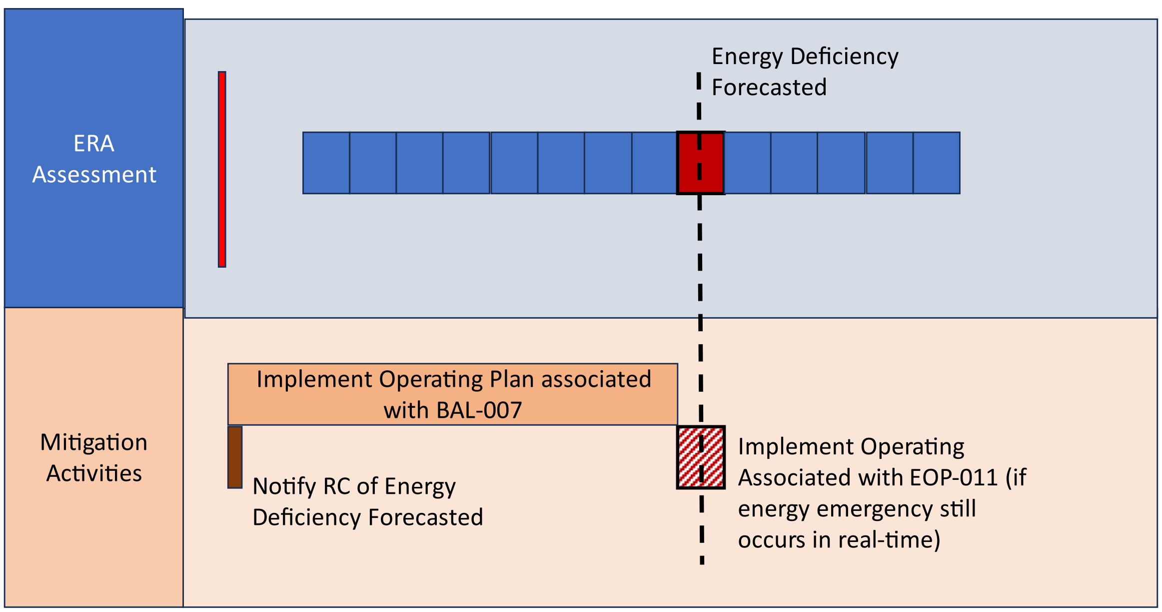

Figure 1. Timeline of ERA performance and Operating Plan Implementation if the forecasted energy deficiency is not fully mitigated when EOP-011 Operating Plan is still required.

Additionally, the BAL-007-1 assessments require considering energy risk which can only be performed by looking at an assessment over a time period with multiple time steps and considering the fuel supply and the production from just-in-time, variable energy resources. While EOP-011 Requirement R2 includes “Energy Emergencies” as a risk that Operating Plans must address, these assessments have generally been performed as capacity assessments, or potentially a series of capacity assessments in succession, which do not necessarily include variable energy and fuel risk, especially over a longer period of time. BAL-007-1 explicitly requires including these elements in an assessment and set criteria regarding when risks need to be addressed through Operating Plans.

The Balancing Authority (BA) may require additional data from other entities and should consider this when documenting the process. While BAL-007-1 does not require other entities to provide necessary data, TOP-003 requires the BA to "maintain a documented specification for the data necessary for it to perform its analysis functions…" in Requirement R2 and requires the other entities to provide the data in Requirement R5. To provide further clarity in TOP-003, "Near-term Energy Reliability Assessments" has been added to the list of activities for which the Balancing Authorities maintain and distribute a data specification for which applicable entities are required to provide.

Proposed New Terms:

Energy Reliability Assessment (ERA) – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

Rationale

The ERA definition was added to allow for Energy Reliability Assessments to be performed in different time horizons using similar processes prescribed by NERC standards, but also through other processes while maintaining a consistent understanding of what an ERA is. These assessments are intended to look at the wide variety of resources available to serve load's energy requirements not only in the near-term but also in other time horizons including the long-term planning horizon. ERAs go beyond the existing scope of the capacity assessments that have traditionally been performed to look more closely at energy needs.

The definition for Near-Term Energy Reliability Assessment provides further details for this specific type of ERA. Within the definition are requirements for the duration of a Near-Term ERA. It is the intent that Near-Term ERAs are performed on a routine basis and look at the time period that covers the next several days to weeks, and that all time periods will be effectively covered by some iteration of a Near-Term ERA. Assessments would be repeated as no later than when one expires to extend the outlook for the BA performing the ERA. To that end, in the interest of maintaining relevancy of the ERA, a five-day to six-week limit is placed on the duration. While six weeks is a long period of time, it gives regions the flexibility to assess the energy landscape over a period of time that encompasses the energy risks that they deem to be pertinent. It is expected that most Balancing Authorities will update their Near-Term ERAs on a more frequent basis, but the baseline requirement is flexible to allow for longer periods. The minimum duration of five days gives the Balancing Authority the foresight to evaluate fuel constraints and weather anomalies. Fuel constraints, specifically natural gas scheduling timelines, typically extend through a single day (e.g., today for tomorrow) during the week, and three-day strips over weekends. Holidays introduce a longer strip than the typical weekends. Five-day strips are traded at least once per year and sometimes more than once depending on where holidays fall on the calendar. That construct is one example of the factors that set the minimum of five days for Near-Term ERAs. Weather dependent resources, where prevalent, would drive the consideration for longer-duration assessments. Doldrums in wind and solar production will have a historical expectation for how long they typically last and should be considered with determining the minimum duration of the Near-Term ERA. Finally, there is a requirement that the initialization data being used to perform a Near-Term ERA be current. This is spelled out as "an assessment period that begins no later than two days after the operating day", the operating day being the day on which the ERA is being performed, or started, or completed. One interpretation that meets this requirement is that the first day of the Near-Term ERA is the current day, which is no later than two days out and provides good initialization of the models being used to perform the assessment. What this is intended to prevent is performing all

Near-Term ERAs in a single assessment at the start of a year or season, maintaining current, relevant, and useful information for the BA to make sound decisions.

Requirements:

Requirement R1

Requirement R1 identifies the basis for defining what a Near-Term ERA is. Basic input assumptions are specifically designed by each BA according to their risks and their supply resource mix and demand profiles. Because of differences in risks and in resource mixes and demand profiles between regions, rather than requiring a set of prescriptive elements to assess, each BA is provided with minimum assessment requirements which they will use to define their scope for performing their ERAs and document a rationale.

Balancing Authorities may perform the required ERAs for just their area or a group of BAs may jointly perform their ERAs. This is consistent with existing partnerships (e.g., Reserve Sharing Groups or resource adequacy collaboratives) between BAs that are used for other operations or planning activities and real time operations, and should be reflected in Near-Term ERAs and their associated Operating Plan(s). Should a deficiency be identified, the BAs, regardless of whether they performed their assessment jointly or individually, are expected to utilize all of their available resources, including those in other BA areas. The goal of the ERA is to determine if sufficient energy is available to meet demand at all times.

Demand profiles will be determined by the BA as well. Entities will have a number of items to consider prior to determining their Demand profile. It is up to the BA to determine exactly how Demand will be modeled, including considerations of how demand response is treated. A BA may choose to include market based or dispatchable demand response, but it is recommended that other forms of demand response should not be included, which would leave load reduction options as a last resort (e.g., voltage reduction, load cycling, etc.). Each BA will need to identify what their type of demand response is and when, if ever, to consider it. Load shed should only be identified as part of a plan if this is the last resort.

The heart of an ERA is the modeling of resource capabilities and their fuel supplies. This modeling includes constrained fuel supplies such as natural gas, inventoried fuels such as oil, coal, liquefied natural gas and some hydro, and just-in-time fuels like wind, solar, and run-of-river hydro. ERAs look at the production from generating resources over a period of time, which will impact their operation. Constrained fuels will deplete, limiting the operation of generation (i.e., fuel). All of these considerations go into modeling resource capabilities and operational limitations, including fuel supply.

Energy transfers with other Balancing Authorities is required to be modeled as well. This modeling is simply the interchange between areas that BAs count on in their day-to-day operation of their systems. It is recommended that BAs coordinate these assumptions to ensure consistencies on the common interface, but may not be required depending on the scope of the ERA as it is defined.

Finally, known Bulk Electric System (BES) Transmission constraints, that limit the ability of generation to deliver their output to load, are required to be included in the Near-Term ERA. This requirement was carefully worded such that a power flow or load flow analysis is NOT required to be performed, however

when a system has a known constraint that causes area generation to always be limited under certain specific conditions, and those conditions are expected to occur, then that generation should be reduced in the ERA as well.

ERAs should ensure that every period of time is evaluated, and document the frequency and duration that meets that intent. For example, performing a two-week long ERA every two weeks would meet the requirement. The determination of how long to study will be based on several factors such as system or generation outage recall timing, accuracy of forecast information beyond the next few days, or lead time for fuel replenishment. Each Balancing Authority will conduct a Near-Term ERA for all time periods unless the BA demonstrates that a Near-Term ERA is not necessary. This can be accomplished via screening tools that evaluate all of the factors above for risk and show that risk is low for that period of time. This requires documentation of the methods used to make that determination as well as the evaluation of the factors considered.

Requirement R2

Requirement R2 outlines a minimum set of Scenarios that must be included in a Near-Term ERA. The intent is to provide a mechanism for each BA to gauge whether or not they are close to an Energy Emergency. Credibility of the Scenarios is for the BA to define and document. The selected Scenarios are intended to stress the system, but may fall short of causing an Energy Emergency on their own. For example, raising demand during light load periods may not result in stressed system conditions, but would meet the intent of stressing the system. The BA is in full control of determining what Scenarios are appropriate.

There are four types of Scenarios, two for supply, one for Demand, and a combination of the two based on historically observed conditions that could occur again. Each of the Scenarios can be varied independently or in combination with each other. At least one parameter should be varied enough to stress the system to determine if the (remaining) available resources are robust enough to meet the Demand and Operating Reserves. A possible Scenario for Demand profiles could be raising Demand from a 50/50 profile to a higher profile, such as a 90/10 or maximum load Scenario, to measure the impact to the system and determine if energy shortfalls are forecasted. There are two supply side Scenarios to be included in the ERA. The first is an energy supply contingency that effectively removes energy resources from the base case and runs it again. Large energy resources may be the same as large capacity resources, but not necessarily in all cases. Typically, the results of the base Scenario will show the analyst what the largest source of energy is, which would be removed from the energy supply contingency Scenario. The second supply Scenario removes a set of resources that are supplied by the same fuel supply. This is traditionally thought of as natural gas supplying multiple generating stations and may be just that, but could also be a set of wind turbines that are closely situated, where a storm or lull could render them unavailable or with a very low production for a period of time. It could also include the loss of energy from solar panels that are covered by snow or smoke from a fire. The final Scenario is more versatile and can be tailored by the BA based on actual events that happened and could happen again within the horizon being assessed. This Scenario should be specific to the region, the time of year, the forecasted conditions, and any other expected conditions that the BA includes in the Near-Term ERA. For example, modeling a snow storm that covers solar panels during the winter months in a location where snow is prevalent makes sense but modeling the same storm during the

summer is unreasonable and is not expected to be done. It is possible that this Scenario is simply documented that there are no historical events that fit the current forecasted conditions, or that the Scenario is the same as those described in R2.1.1 through 2.1.3. When this occurs, the Balancing Authority should include that description in their process.

Regardless of the chosen energy and fuel Scenarios, it is up to the BA to determine which resource or set of resources are included in the ERA. The choices by the BA in Scenarios must be identified and documented.

Requirement R3

The time horizon specified in the Near-Term ERA definition offers a different vantage point than next day and real-time capacity assessments. The actions that a BA can take due to an identified risk of an energy shortfall are different when identified days to weeks earlier than if waiting for a next day or real-time capacity assessment. They are also different when comparing the energy aspect of the ERA to a capacity assessment. An example of actions that could be taken based on the results of a Near-Term ERA that may not be available for a next day or real-time assessment include requesting for energy resources or transmission facilities to return from maintenance or construction outages earlier than planned or to postpone a planned outage. Additional actions that could be considered for an energy shortfall that would be overlooked in a capacity assessment is the conservation of stored fuel or the optimization of energy storage (e.g., pumped storage hydro or batteries). If an entity were to wait for the next day studies to identify a risk, fewer options for the BA to avoid an energy risk in real time would be available.

Provisions for communication with the Reliability Coordinator is simply a documented process including the forecasted conditions when the RC will be alerted to the results of the Near-Term ERA and/or the implementation of Operating Plans. Many of the actions that are included in Operating Plans will not require communication of any kind (e.g., waiting for better forecasts), but some may require that communication (e.g., recall of transmission facilities). The procedure used to document the performance of Near-Term ERAs including a section that clearly defines what communications are required by the BA meets this requirement.

Requirement R3 requires BAs to develop Operating Plans prior to forecasting Energy Emergencies through ERAs to minimize their effects. These Operating Plans are developed so that in the event that an ERA shows that a BA may have insufficient energy, they will have an Operating Plan ready to implement, per Requirement R3, that has been developed and communicated before system conditions are unfavorable and be ready for later implementation. Operating Plans are expected to include actions that can be performed by the BA within the time horizon for which the ERA is designed, near-term. The actions that BAs may include in Operating Plans will also provide information to the BA regarding how long the assessment period of the ERA might need to be (Requirement R1) such that they can have time to accomplish the actions identified. For example, if actions that could minimize potential Energy Emergencies take two weeks to accomplish, the ERA should be looking at least two to three weeks into the future.

As discussed in the Relationship to other Standards section, the Operating Plans developed based on this requirement are not intended to supersede Operating Plans associated with TOP and EOP standards but to

complement them and include actions that could reduce the likelihood or severity of an energy deficiency occurring in real-time. To that end, the BA develops an appropriate Operating Plan for a forecasted Energy Emergency that is identified by an ERA. Depending if the ERA is completed weeks or days prior to the forecasted Energy Emergency, the BA decides on suitable plans to reduce the impact. Since the Operating Plans are being implemented based on assessments looking days to weeks ahead, considering the associated uncertainty of the results, BAs may decide to exclude actions in the BAL-007-1 Operating Plans which would only need to occur much closer to the projected event or only plan to implement those actions if the projected conditions of the ERA appear that they will still occur. For example, an Operating Plan may include increasing the frequency of performing ERAs in order to monitor whether the forecasted Energy Emergency is more or less likely as the uncertainty of input data to the assessment decreases and other actions in the Operating Plan have been implemented. Again, the goal of performing an ERA is to identify those times when a forecasted Energy Emergency might occur. The developed Operating Plan should have steps that can be taken to reduce, or mitigate, the forecasted Energy Emergency.

The ERA Operating Plans should be designed to be adaptable to unfolding conditions and proactive enough to possibly avoid an energy shortage through advanced actions. As an example, to illustrate the Operating Plan uses, when an ERA is performed two weeks ahead of a calculated shortfall then potential actions have a two-week timeline to perform the appropriate action plans as well as monitor if the identified risk conditions have changed. For instance, if the results from a two-week duration ERA during an extremely cold period determines an Energy Emergency may occur, the BA's Operating Plan could include the following actions:

- Survey scheduled outage system to determine if any generation currently out for maintenance can return earlier than planned.
- Survey if any transmission outages affect either generation deliverability or import capability. If yes, can they be returned to service prior to the forecasted Energy Emergency.
- Survey if generation and transmission scheduled to go out can defer their outages until after the event.
- Communication with Reliability Coordinator and other relevant entities of the projected risk (e.g., government authorities for assessing the need and strategy for public appeals for conservation, or other BAs to account for expected imports or exports and potentially facilitate higher transfers).
- Ensure all energy storage units can be fully available to help mitigate energy shortfalls.
- Increase frequency of performance of ERAs, including possibly daily, and assess energy availability and have Operating Plan actions conditional on the level of risk.
- If ERA results still indicate unacceptable risk of energy deficiency two days prior to projected event, instruct thermal plants to warm up leading up to event to avoid outages due to ice formation and cold-start issues.

Ideally, these actions will reduce or prevent an Energy Emergency that might occur in real-time. However, if the Energy Emergency still occurs, these actions should reduce the energy deficiency and prepare the BAs

to implement an emergency Operating Plan. This scenario is intended only to be one simple illustrative example that does not reflect all potential Operating Plan actions or actions that BAs in all regions can do.

While scheduling increased imports can be a part of the Operating Plan, it is imperative that the BA verify that the resources they have scheduled will continue to be there to solve their Energy Emergency. It should not be assumed that once imports are scheduled, this energy is a firm supply. Both BAs may be impacted by the event causing an Energy Emergency for both areas. The supplying entity may not be able to honor their agreement to provide this energy.

Requirement R4

Requirement R4 specifies that the near-term ERA be performed as designed.

Requirement R5

Requirement R5 specifies what constitutes two circumstances that identify a forecasted Energy Emergency. The forecasted Energy Emergency conditions are intended to be a clear threshold where the ERA results identify levels of impending risk and require actions be performed to minimize the potential they will occur. The definitions of what constitutes a forecasted Energy Emergency are in alignment with the Energy Emergency Alert (EEA) definitions in EOP-011. The difference for BAL-007-1 is that instead of being a real-time Energy Emergency, these would be forecasted events. The goal here is that if an Energy Emergency is forecasted in an ERA, the associated Operating Plan will have targeted steps to help minimize the forecasted Energy Emergency before it gets to be an Energy Emergency in the next day and real-time timeframes.

There are three EEA levels, two of which are associated with forecasted Energy Emergencies. The criteria for forecasted Energy Emergency apply also to Scenarios identified in Requirement 2. This level of granularity allows for the BA to design an Operating Plan that fits the specific situation. Some Scenarios may be expected to enter the lower levels of an Energy Emergency, and the actions in an Operating Plan should be appropriate for that combination.

Finally, by leveraging the existing terms used in EOP-011 for EEA, clear and well-understood definitions are already in place which require little to no training, beyond the advanced timing associated with BAL-007-1. BAs have existing interpretations of how they respond when nearing or entering an EEA and the existing interpretations are expected to be used, including those that involve interaction with Reserve Sharing Groups.

Requirement R6

Requirement R6 requires that the BA review their process, Scenarios, and Operating Plans, in Requirements R1 through R3, to determine if any changes are needed. The BA shall review this documentation at least once every 24 months. Due diligence during the design and review phases by the BA is required to identify potential risks and possible actions that could minimize those risks that would lead to an energy shortfall in the near-term timeframe.

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Violation Risk Factor and Violation Severity Level Justifications

Project 2022-03 Energy Assurance with Energy-Constrained Resources

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2022-03 Energy Assurance with Energy-Constrained Resources. 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 DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

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

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

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

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard
FERC expects a rational connection between the sub-Requirement VRF assignments and the main Requirement VRF assignment.

Guideline (3) – Consistency among Reliability Standards
FERC expects the assignment of VRFs corresponding to Requirements that address similar reliability goals in different Reliability Standards would be treated comparably.

Guideline (4) – Consistency with NERC's Definition of the Violation Risk Factor Level
Guideline (4) was developed to evaluate whether the assignment of a particular VRF level conforms to NERC's definition of that risk level.

Guideline (5) – Treatment of Requirements that Co-mingle More Than One Obligation
Where a single Requirement co-mingles a higher risk reliability objective and a lesser risk reliability objective, the VRF assignment for such Requirements must not be watered down to reflect the lower risk level associated with the less important objective of the Reliability Standard.

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a "binary" type requirement must be a "Severe" VSL.
Do not use ambiguous terms such as "minor" and "significant" to describe noncompliant performance.

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

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

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

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

VRF Justifications for BAL-007-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the process for conducting Energy Reliability Assessments for the near-term time horizon which are required in defining the minimum standards by which Energy Reliability Assessments will be performed 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 BAL-007-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 or Part 1.2.	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 through Part 1.2. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for one of the elements in Requirement R1 Part 1.3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.

VSL Justifications for BAL-007-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for BAL-007-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining a set of scenarios or a method of Scenario creation which are required in defining the minimum standards by which near-term Energy Reliability Assessments will be performed 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 BAL-007-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include one of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include two of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include three of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of Scenario creation but did not include any of the conditions listed in Requirement R2 Part 2.1. OR The Balancing Authority failed to document a set of Scenarios or a method of Scenario creation for use in performing Near-Term ERAs.

VSL Justifications for BAL-007-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not 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 BAL-007-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term Energy Reliability Assessment, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s) 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 BAL-007-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority documented an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs.

VSL Justifications for BAL-007-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that near-term Energy Reliability Assessments were not performed according to the process documented in Requirement R1 using the scenarios or methods documented in Requirement R2 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 BAL-007-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to perform a Near-Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.

VSL Justifications for BAL-007-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that if an Operating Plan(s) was not implemented once a near-term Energy Reliability Assessment identified one or more forecasted Energy Emergencies it 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 BAL-007-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a Near-Term ERA identified any of the forecasted conditions in Requirement R5.

VSL Justifications for BAL-007-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R6	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that each if a Reliability Coordinator did not notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of the forecasted condition(s) and the Balancing Authority's Operating Plan(s) 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 BAL-007-1, Requirement R6			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority reviewed information that contained the Near-Term ERAs process, the ERA Scenarios or methods, and Operating Plan(s) but failed to update within 24 months.	The Balancing Authority failed to review and update information that contained the Near-Term ERAs process, the ERA Scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.

VSL Justifications for BAL-007-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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-003-6

VRF Justification for TOP-003-7, Requirement R2

The VRF did not change from the previously FERC approved TOP-003-6 Reliability Standard. The modifications made to R2 are similar in content to the previous draft and therefore the VRF remained low.

VSL Justification for TOP-003-7, Requirement R2

Please refer to the VSL table located below.

VRF Justification for TOP-003-7, Requirement R4

The VRF did not change from the previously FERC approved TOP-003-6 Reliability Standard. The modifications made to R4 are similar in content to the previous draft and therefore the VRF remained low.

VSL Justification for TOP-003-7, Requirement R4

Please refer to the VSL table located below.

VSLs for TOP-003-7, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented

			specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-7, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional assessment to Requirement R2. The proposed VSL was modified to reflect the additional assessment. It does not have unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, therefore, consistent with the requirement.

VSL Justifications for TOP-003-7, Requirement R2	
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.

VSLs for TOP-003-7, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to three entities, or more than10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-7, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional assessment to Requirement R4. The proposed VSL was modified to reflect the additional assessment. It does not have unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Formal Comment Period Open through November 4, 2024
Ballot Pools for TOP-003-7 Forming through October 18, 2024

Now Available

A 47-day formal comment period for **draft three of BAL-007-1 Near-term Energy Reliability Assessments** and **draft one of TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection** is open through **8 p.m. Eastern, Monday, November 4, 2024.**

Regarding BAL-007-1, the standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

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 **for TOP-003-7** are being formed through **8 p.m. Eastern, Friday, October 18, 2024.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*

- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

An additional ballot for BAL-007-1 and initial ballot for TOP-003-7 and their implementation plans, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 25 – November 4, 2024**.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources 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:	2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 TOP-003-7 and Draft 3 BAL-007-1
Comment Period Start Date:	9/19/2024
Comment Period End Date:	11/4/2024
Associated Ballots:	2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 Implementation Plan IN 1 OT 2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 TOP-003-7 IN 1 ST 2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 AB 3 ST 2022-03 Energy Assurance with Energy-Constrained Resources Implementation Plan AB 3 OT

There were 54 sets of responses, including comments from approximately 167 different people from approximately 103 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

BAL-007-1 Near-term ERAs

1. The drafting team (DT) modified BAL-007-1 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

BAL-007-1 Near-term ERAs

2. The DT updated the implementation plan to allow for 24 months for BAL-007-1 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

BAL-007-1 Near-term ERAs

3. The DT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request 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.

BAL-007-1 Near-term ERAs

4. Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

TOP-003-7

5. The drafting team (DT) modified TOP-003-6 to ensure industry that Near-Term ERA type data can be requested. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

TOP-003-7

6. The DT drafted the TOP-003-7 implementation plan allowing 18 months to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

TOP-003-7

7. The DT proposes that the modified TOP-003-7 meets the Standards Authorization Request 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.

TOP-003-7

8. Provide any TOP-003-7 additional comments for the SDT 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	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO

					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO
					Angela Wheat	Southwestern Power Administration	1	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group, Inc.	3	RF
					Michelle Hribar	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
					Candace Morakinyo	WEC Energy Group, Inc.	4	RF
Independent Electricity System Operator	Helen Lainis	2		IRC SRC	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Charles Yeung	SPP	2	SERC
					Elizabeth Davis	PJM	2	RF
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF

					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
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
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC

					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Travis Grablander	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC

					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC

					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Nicolas Turcotte	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Erin Cullum	Southwest Power Pool Inc.	2	MRO
					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Mason Favazza	Southwest Power Pool Inc	2	MRO
					Sherri Maxey	Southwest Power Pool Inc.	2	MRO

					Josh Phillips	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Public Utility District No. 1 of Chelan County	Tamarra Hardie	6		CHPD	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC
					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Santee Cooper	Vicky Budreau	3		Santee Cooper	Lachelle Brooks	Santee Cooper	1,3,5,6	SERC
					Diana Scott	Santee Cooper	1,3,5,6	SERC

BAL-007-1 Near-term ERAs

1. The drafting team (DT) modified BAL-007-1 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

R2.1.1-R2.1.3 lack specificity, creating risk that the scenarios postulated by BAs will fall short of the actual challenges that may be faced. This is especially the case when applying the rule, "The Near-Term ERA process shall account for…Forecasted or assumed Demand profiles." PJM's forecast for Winter Storm Elliott was low by 12 GW; ERCOT missed by 10 GW. BAL-007 ERAs may have little value until the forecasting state of the art advances enough to eliminate this problem.

A far more secure approach is to place more emphasis on R2.1.4, historical precedents. That is, require that ERCOT study a repeat of Winter Storm Uri, require that PJM study a repeat of the record-setting cold of January 1994, etc. The weather data for the plants we had in Texas in 2021 showed that Uri and the deep freeze event of Dec. 1989 were remarkably similar. There is no need for guesswork or statistical studies; just adopt the view that what happened before will eventually occur again.

BAL-007 should also require sufficient scenarios to address the changing mix of generation, e.g. a deep freeze with high wind for conventional plants, an ice storm for wind farms, and combination events (such as Winter Storm Uri).

Above all else, BAL-007 should make it clear that limiting the scenarios being studied to the EOP-012 ECWT is not sufficient. Recent generation capacity emergencies have generally involved temperatures well below the ECWT, plus high winds.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA appreciates the effort made by the Drafting Team (DT) to make changes based on BPA's comments during the previous comment period. BPA sees the value of the changes made but has identified an area for improved clarity in this draft. Please see comments below.

To allow for more defined coordination with other BAs, and to meet the intent of the "…Jointly with other Balancing Authorities…" language used throughout the BAL-007-1 requirements, BPA recommends the creation of a new term and definition similar to Reserve Sharing Group (RSG) in the NERC Glossary of Terms, as a NERC Compliance Registration (as seen with RSG, FRSG, etc.), and revisions to BAL-007-1 Requirement language, in order to allow an entity to be the 'Responsible Entity' for multiple BAs.

The intent of this new term and registration is to be included in BAL-007-1 in the applicability section and/or the Requirements to provide similar clarity to the placement of language used in BAL-002 and BAL-003, as seen below. BPA believes adding this to the standard would create continuity with other defined terms and registration types and clearly execute the intent for BAs to 'jointly' meet the reliability objectives outlined in BAL-007-1.

Section 4, Applicability of BAL-002-3:

4.1.1.1. "A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

4.1.2. Reserve Sharing Group

Section 4, Applicability of BAL-003-2:

4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity.

4.1.2. Frequency Response Sharing Group

BAL-003-2, Requirement R1:

R1. "Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall…"

BPA believes its recommendations in question 1 align with benchmark 1, 8, and 10 of the 'Ten Benchmarks of an Excellent Reliability Standard' as referenced in the NERC Standards Process Manual, Section 4.4.2, 'Draft Reliability Standard'. BPA also views its recommendations as 'in scope' of this project as noted in bullet one of the SAR: "…create defined terms as needed…"

Additionally, BPA agrees with the Near-Term ERA Definition.

Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

The language in the current draft 3 BAL-007-1 R1 will allow entities to perform no evaluation of forecasted Demand and resource capabilities for self-determined time period(s). The language of BAL-007-1, draft 2 is preferred as compared to draft 3.

Likes 0	
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	

Answer	No
Document Name	

Comment

The requirements in BAL-007-1 Draft 3 identify that “Each Balancing Authority shall, individually or jointly with other Balancing Authorities” perform/comply with the standard, however, this statement creates ambiguity and does not clearly specify ownership of compliance. To enhance clarity and accountability, it is essential to delineate the ownership and responsibility for compliance within the requirements more precisely. This can be achieved by specifying which functional entities are accountable for each compliance aspect and detailing the actions they must take. Such specificity facilitates better adherence to the requirements and clearly specifies ownership of compliance. In addition, the Measurement criteria should specify that each Balancing Authority shall have evidence of compliance. If the requirements include more than one BA or group of BAs, the measurements should be clear as to compliance ownership and mirror each requirement’s language.

For example, in BAL-002-WECC-3, the Functional Entities Applicability section 4.1, the Standard clearly defines who the responsible entity is for reporting:

4.1.1 Balancing Authority

4.1.1.1 The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

4.1.2 Reserve Sharing Group

4.1.2.1 The Reserve Sharing Group when comprised of a Source Balancing Authority becomes the source Reserve Sharing Group. 4.1.2.2 The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group.

There is concern that as BAL-007-1 Draft 3 includes each BA individually or jointly with other BAs, more specifically “jointly with other BAs” does not explicitly define who the responsible entity is for reporting. Since it is not written, a Balancing Authority may be under the impression that the group is the responsible entity for reporting and not the Balancing Authority themselves. With the inclusion of additional parties, it would be best served to explicitly define who the entity responsible is for compliance with the Standard.

Likes 0	
Dislikes 0	

Response

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson

Answer	No
Document Name	

Comment

RF has a concern with 1.3.1. An energy assessment should be required for each operating day. The intent of the standard is to conduct an energy assessment to identify a possible energy shortfall, by allowing an overly broad opt out option the intent of the standard will be lost. An applicable study should be on hand for each operating day (although performing a study periodically as proposed is acceptable).

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	

The flexibility and lack of defined methodology for defining time periods and criteria for identifying low risks is understandable, and perhaps appreciated, due to regional and system differences between entities. However, the lack of specificity creates concerns about how NERC will judge the proposed methodologies and criteria and how compliance will be measured/assessed.
Creating a 5-day plan will be very specific to conditions that have the potential to change, limiting the ability of our teams to act appropriately if they feel tied to the plan. Conversely, plans that are as long as 6 weeks are likely lacking timely enough data for decision making.
Additionally, the listed scenarios in R2 may not always be relevant and it's unclear whether each assessment must include an evaluation of listed scenarios.
It is reasonable for to expect a level of preparedness planning when the scenarios in R2 are forecast but an action plan for mitigating risk is more what's needed rather than an operating plan to be implemented.
The ability to plan with other balancing authorities is appreciated.

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	

We understand the purpose of the proposed BAL-007-1 reliability standard and Near-term Energy Reliability Assessment (ERA), however, a Near-term ERA is only necessary for special operating conditions which may be less than 10% of the time for many Balancing Authorities (BAs). Under normal operating conditions when the load is not high and resource availability is good, the Outage Coordination process in IRO-017-1 and Operations Planning process in TOP-002-4 would cover the desired contents of the Near-Term ERA, so the assessment is not needed during normal operating conditions. The proposed BAL-007-1 requires too much procedural burden during normal operating conditions.

We suggest the Drafting Team revise Requirement R1 to reverse the order so that BAs document a process that accounts for ***when*** to conduct a Near-Term ERA first. Criteria for ***when*** BAs are required to conduct a Near-Term ERA should be listed as the first sub-requirement (e.g. Requirement R1.1) so that 90% of the time BAs do not have to complete one.

We agree with the details listed in Requirement R1.1.1 through R1.1.4. for what must be accounted for and the duration of the Near-Term ERA in Requirement R1.2., however, these should be listed after conditions for ***when*** a Near-Term ERA is required. As currently written, the methodology for ***when*** a Near-Term ERA is not necessary because there is a low-risk of an Energy Emergency occurring is included down in Requirements R1.3.1 and R1.3.2. Since this is where BAs will operate more than 90% of the time, the conditions triggering a Near-Term ERA should be listed first in Requirement R1 and not last. In addition, we suggest the Drafting Team simplify the original Requirement R1.3 and make it the new R1.1 as follows: R1.1 The Near-Term ERA process shall specify the operating conditions for which the Balancing Authority will conduct a Near-Term ERA.

Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	No
Document Name	
Comment	
The Los Angeles Department of Water and Power (LDWP) appreciates the opportunity to provide feedback on BAL-007-1. LDWP notes that many utilities, including those within our Balancing Authority Area, already comply with rigorous planning requirements set forth by state or local regulatory authorities, suggesting that the additional planning directives in BAL-007-1 may be potentially redundant. If the intent is to improve coordination with the Reliability Coordinator (RC) during energy-constrained events, LDWP recommends that the Standard emphasize this goal directly, rather than imposing new planning mandates. This focused approach would prevent duplicating existing regulatory obligations.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT recommends that Requirement R1, Part 1.1 be revised to clarify that the Near-Term ERA process must account for the listed items as they may apply during the time period that any given Near-Term ERA assesses, not as generic items. ERCOT likewise recommends that Requirement R1, Part 1.1.4 be revised to clarify that it refers to BES transmission constraints known at the time the Near-Term ERA is performed.	

ERCOT further recommends that Requirement R1, Part 1.3 be clarified by replacing "the frequency with which the Balancing Authority will conduct Near-Term ERAs" with "how often the Balancing Authority will conduct Near-Term ERAs."

To further clarify the Balancing Authority's discretion in developing Scenarios under Requirement R2, ERCOT recommends that Part 2.1 be revised as follows: " . . . (ii) other Scenarios that stress the system **to the degree determined and documented by the Balancing Authority** due to the following conditions . . ."

ERCOT also recommends that Part 2.1.4 be revised to indicate that it refers to historical conditions from the time of year that the Near-Term ERA in question is assessing, thereby clarifying that responsible entities are not (for example) required to consider historical summer conditions during a Near-Term ERA that assesses a time period in the winter.

ERCOT appreciates the drafting team's revisions to Requirements R3 and R5; however, ERCOT is concerned that these Requirements could be read to require potentially unnecessary actions based on assessments that rely on incomplete information (such as information regarding fuel supply chains) to examine events that have a very low probability of occurring. Consequently, ERCOT recommends that Requirements R3 and R5 be removed from BAL-007 so that entities can focus on dialing in their ERAs under this first version of BAL-007. If the requirements are retained, ERCOT recommends that Requirement R3 be revised to more explicitly indicate that Operating Plans are only required to be documented for forecasted EEA2 and EEA3 circumstances, consistent with Requirement R5.

Finally, ERCOT recommends that "documented" be replaced with "provided" in Measure M6 to better align with the language used in Requirement R6.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy has no comments on BAL-007-1's proposed draft.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Duke Energy supports the proposed changes made to BAL-007-1, Draft 3.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	Yes
Document Name	

Comment

PNM agrees with the changes to BAL-007-1.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	Yes
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 1

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	Yes
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the proposed changes to BAL-007-1, Draft 3.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed changes made to BAL-007-1, Draft 3.	
Likes 0	
Dislikes 0	
Response	

Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The response if provided on behalf of Exelon representing Segments 1 and 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 the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, 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	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 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	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
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	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends using consistent verbiage for maintaining documented processes/specifications in BAL-007-1 and TOP-003-7. BAs and TOPs should be documenting and maintaining the processes and specifications. Texas RE recommends the following revisions in BAL-007-1 Requirements R1, R2, and R3: R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities**, maintain a documented process** for conducting Near-Term Energy Reliability Assessments (ERA). R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, **maintain a documented set** of Scenarios, or a method for developing Scenarios, for use in performing Near-Term ERAs. In Requirement R3, Texas RE is concerned that there is no limit associated with the probability of the risk level for documenting the operating plan(s). BAs should have the option to define the probabilistic threshold for declaring the Energy Emergency based on the simulations. It may be administratively cumbersome to document Operating Plan(s) for each ERA simulations for which the simulations indicate a low probability of an Energy Emergency. The BAs should define the probabilistic risk threshold limit based on their system conditions/scenarios (for example, if the probability of declaring Energy Emergency is less than X%, BAs should not have to document any Operating Plan(s)).	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

WECC voted Affirmative, but suggests the DT consider the following:

Requirement R2 provided the BA (or joint BAs) to either document a set of Scenarios OR a **method** for developing Scenarios however Requirement R2 Part 2.1 only describes a "set of Scenarios" and does not mention "method". Suggest changing language to 2.1 "The set of Scenarios, **or the method for developing Scenarios** must include…." Requirement R3 should pluralize Reliability Coordinator as the BAs may very well have different Reliability Coordinators but intend to use the same Operating Plan(s). Requirement R6 should delineate the efforts of reviewing, updating, and providing the materials listed. An Near-Term ERA, by definition is Near-Term and will be reviewed and updated in a much shorter timeframe than 24 calendar months. Operating Plans are similar in nature in that they could cover a short time period. Perhaps the process documentation (Near-Term ERA document, Scenario method, methodology for not doing a Near Term ERA—which is not mentioned here) should be provided but the outputs need a more realistic time period for provision to the RC.

Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	

For an entity whose generation is mostly reservoir-based hydro, the "near-term energy reliability assessment" horizon does not ensure reliability. Reliability is rather achieved on an annual and multi-annual horizon where water consumption, water levels and adequate storage are analyzed. In the near-term, refinement of what was planned in the long term is what occurs. In the case where an entity has full control over the reservoir, the notion of fuel supply, energy risk and energy emergency is low because this type of reservoir-based hydro is not a constrained resource. Is the new R1.3 meant to cover this scenario?

Likes 0	
Dislikes 0	
Response	

BAL-007-1 Near-term ERAs

2. The DT updated the implementation plan to allow for 24 months for BAL-007-1 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT appreciates the revised implementation timeline; however, ERCOT notes that entities are developing improvements to internal processes to improve energy capabilities for the operations planning horizon while these new NERC requirements are still being finalized. It is unknown at this time what the impacts of the new requirements will be, but resources will be needed to fully integrate and implement the NERC standards with internal processes. Consequently, while ERCOT appreciates the updates to the implementation plan, ERCOT requests that the implementation plan be further revised to allow at least 36 months for the implementation of all Requirements in BAL-007-1.	
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 submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	

Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	

If this Standard becomes enforceable, a 24-month implementation timeline would provide sufficient time for compliance.

Likes 0	
Dislikes 0	

Response
Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment
The response if provided on behalf of Exelon representing Segments 1 and 3

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
Yes, limiting the proposed BAL-007-1 to Balancing Authorities makes the 24-month implementation reasonable.

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 updated implementation plan.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the proposed updated implementation plan.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

See EEI Comments

Likes 0	
Dislikes 0	

Response

Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
APS agrees with the updated Implementation Plan to allow for 24 months for BAL-007-1 to become compliant.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 2	
Likes 0	
Dislikes 0	
Response	

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM agrees with the 24 month implementation timeline.	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE noticed there is no Effective Date header as is typical in other implementation plans.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy supports the proposed updated implementation plan.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments on BAL-007-1’s implementation plan.	
Likes 0	
Dislikes 0	

Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,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	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
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	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
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	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, 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	
Anna Lavik - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro is unable to support the implementation plan at this time as additional clarifications to Requirements are needed prior to assessing the implementation plan.	
Likes 0	
Dislikes 0	
Response	

BAL-007-1 Near-term ERAs

3. The DT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request 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.

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
There was no cost/benefit study to show this is a cost-effective approach. It appears that BAs will have to conduct assessments that they were never intended to do, and they will have to aquire the specialized skills needed.	
Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	
There is no technical justification of the reliability-related benefits and costs for this project.	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
No cost-benefit explanation or analysis was provided.	

Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	No
Document Name	
Comment	
Many utilities, including those within LDWP's Balancing Authority Area, fulfill planning requirements set by their state or local regulatory authorities, making this Standard potentially redundant. From LDWP's perspective, this Standard does not improve reliability and only adds an additional compliance burden to entities.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments on BAL-007-1's cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The response if provided on behalf of Exelon representing Segments 1 and 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 the submitted comments by EEI.

Likes 0	
Dislikes 0	

Response

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Brooke Jockin - Portland General Electric Co. - 1

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, 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	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
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	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF	
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	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
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	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
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 will not submit comments on the cost effectiveness of the proposed BAL-007-1 Reliability Standard.	
Likes 0	
Dislikes 0	
Response	

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

BAL-007-1 Near-term ERAs

4. Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
In the Near-Term Energy Reliability Assessment definition, it is unclear which operating day the definition is referring to, and it is unclear whether the term “assessment period” refers to the time period being assessed or the time the responsible entity spends performing the assessment. To clarify this, ERCOT recommends that the definition be revised to read as follows: “An Energy Reliability Assessment that assesses a time period that is between five days and six weeks long and begins no later than two days after the operating day in which the responsible entity begins conducting the Near-Term Energy Reliability Assessment.” In BAL-007-1, Requirement R1, Part 1.2, it is likewise unclear whether “duration” refers to the time period being assessed or the time the responsible entity spends performing the assessment. To clarify this, ERCOT recommends that Part 1.2 be revised to read “The Near-Term ERA process shall specify the length of the time period that the Balancing Authority’s Near-Term ERAs will assess.”	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company supports the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	
Document Name	

Comment	
LDWP also have the following additional comments: 1. Because many utilities already have a comprehensive forward-looking plan that mirrors the Near-Term ERAs, creating a standard will cause undue burden upon the utilities without adding any margin to reliability. This undue burden would come in the form of additional documentation creation, documentation retention, and resources to effectively comply to the new Near-Term ERA requirements throughout the year and during audits (internal and external). 2. Clarification on Reporting Intent: Once a report is submitted to the RC, the Standard does not clearly specify any further actions beyond raising awareness. Is the primary intent of the Standard solely to inform the RC, or are additional measures anticipated? 3. Defining Forecasted Energy Constraints: Energy Emergency Alerts (EEAs) pertain to real-time events, whereas this Standard addresses forecasted energy or capacity shortfalls. LDWP suggests establishing a separate term, such as "Energy or Capacity Constrained Events" (ECCE), to distinguish forecasted constraints from real-time emergencies. 4. Is sub-requirement 2.1.2 essential? Entities are already mandated by BAL-002 to maintain Operating Reserves, which entities should already plan for through the Energy Planning Assessment period. Duplication of reserve requirements may be unnecessary.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	

It is the continued opinion of ACES that by referencing the EEA levels defined in EOP-011 Atachment 1 Section B, the SDT is deviating from the long-established precedent of NERC Reliability Standards being “stand-alone”.

While we appreciate the difficulties faced by the SDT in meeting the deadline established for the proposed BAL-007-1, we do not agree that referencing another standard is the correct approach. We **strongly** recommend the SDT include the applicable EEA levels in an attachment to BAL-007-1 and not reference another Reliability Standard.

Thank you for the opportunity to 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	
Document Name	

Comment

We would like to thank the Drafting Team for considering the previous comments and understanding the impacts of how this new reliability standard may disproportionately affect organizations based on their business practices, corporate structure, and membership in cooperative organizations.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Please see ACES comments, AEPC has signed on to ACES comments.

Likes 0	
Dislikes 0	

Response

Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
Answer	
Document Name	
Comment	

For Requirement 1.3.1, "Each BA will conduct Near Term ERAs for all time periods…" are we to assume all time periods means the daily time period AND the monthly time period?

For Requirement 1.1.4, do the "Known Bulk Electric System Transmission constraints that limit the ability of generation to deliver their output to load" have to be identified in the Near-Term Energy Reliability Assessment period?

In Requirements 3 & 5, the operating plan for Energy Emergencies (EEA2 and EEA3) are documented in the EOP-011 Operating Plan. Is there a reason to have it here also?

Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	
Document Name	
Comment	

Ameren supports the comments provided by MISO:

Purpose: Should "time horizon" be "Operations Planning horizon?"

To assess, report, and plan to address forecasted Energy Emergencies in the near-term *time horizon*.

Part 2.1.4. Eliminate the word "best" as illustrated below.

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the best information available at the time of Scenario development.

Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	

Document Name	
Comment	

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.

Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	
Document Name	
Comment	

It is difficult to contemplate how NERC will measure compliance with this standard. What if conditions change such that different actions are necessary than what is filed/planned in the ERA? Are there ramifications or compliance issues?

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 project.

Likes 0	
Dislikes 0	
Response	

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson

Answer	

Document Name	
Comment	

In the definition of Near-Term Energy Reliability Assessment the term “no later than two days after the operating day” could be clarified to align better with the definition of Operational Planning Analysis. Clearer language should be used such as “current day” instead of “operating day”.

Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring

Answer	
Document Name	
Comment	

Coordinate “Effective Date” reference in the Standards (TOP-003 and BAL-007) to be consistent—either call out the Project (probably correct way) or the Standard—may be a Quality Review item. For Evidence Retention, six months is an ineffective retention date to demonstrate Requirement R6 evidence. The Evidence Retention needs to extend there to 24 calendar months as a minimum to be auditable in an effective manner. Without evidence being retained there would be a lot of questions needing answered to ascertain efforts.

Requirement R2 VSL discussing the method for Scenario creation but the language of R2 does not support the VSL (see comment above regarding R2). Requirement R6 VSL uses the descriptor “ERA” in front of Scenarios but that is not in the language of the Standard.

In the Implementation Plan, “Assessment” needs to be lower-cased in the proposed definition for Energy Reliability Assessment (second to last word in definition). The Implementation Plan for the definitions does not coincide with implementation of TOP-003-7 which uses “Near-Term Energy Reliability Assessment”. The DT should match the 18 month Implementation Plan of TOP-003-7 to be effective for the definitions.

Likes 0	
Dislikes 0	
Response	

Jessica Lopez - APS - Arizona Public Service Co. - 3

Answer	
Document Name	
Comment	

APS offers the following comments for consideration:

- Currently, the BAL-007-1 Draft 3 “Purpose” states: *To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.*

The purpose statement as written appears to indicate that Balancing Authorities are to assess Energy Emergencies, report Energy Emergencies and address Energy Emergencies which is not the intent of the proposed Standard. Rather, the intent is for Balancing Authorities to assess their specific risks to mitigate potential Energy Emergencies and mitigate.

To provide greater specificity, the Standard Drafting Team should consider the following proposed revisions to the BAL-007-1 purpose statement as such: *To ensure the Balancing Authority has documented its Near-Term Energy Reliability Assessment process for identifying its risks, establishing plans to address risks, implement actions where applicable and report to its Reliability Coordinator(s).*

- The BAL-007-1 Draft 3 version proposes to remove the Reliability Coordinator from the Standards Applicability and solely identifies the Balancing Authority. In the BAL-007-1 Draft 3 version, Requirement 6 requires the BA to provide its Near-Term ERA process, scenarios, and Operating Plans to the RC, however, it is unclear what the expectation is for the Reliability Coordinator upon receipt of the information. The Standard Drafting Team should consider incorporating and/or marrying the expectations in Reliability Coordinator related Standards, such as IRO-010-4.
- The Balancing Authority and overall grid reliability are essential functions of electricity providers. In order to achieve and maintain this high level of reliability, providers already perform near term assessments of load and resource balances, reserve margins and fuel availability on a continuous basis. When potential problems are identified, mitigating actions are taken. Adding additional administrative burdens to document common industry practices is unnecessary and wasteful, potentially tying up resources that would be more effective elsewhere. This proposed standard would only add administrative burdens and costs to entities without adding incremental reliability benefits.

Likes 0	
Dislikes 0	

Response

Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	
Document Name	
Comment	
Purpose: Should "time horizon" be "Operations Planning horizon?" To assess, report, and plan to address forecasted Energy Emergencies in the near-term *time horizon*. **Part 2.1.4.** Eliminate the word "best" as illustrated below. **2.1.4.** Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.	
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	
Ben Hammer - Western Area Power Administration - 1	
Answer	

Document Name	
Comment	

Suggest modifying:

Purpose: “To assess, report, and plan to address forecasted Energy Emergencies in the **Operations Planning** time horizon”.

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based upon the information available at the time of Scenario development.

Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	
Comment	

Purpose: Should “time horizon” be “Operations Planning horizon?”

To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.

Part 2.1.4. Eliminate the word “best” as illustrated below.

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.

Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	
Comment	

Purpose: Should “time horizon” be “Operations Planning horizon?”

To assess, report, and plan to address forecasted Energy Emergencies in the near-term *time horizon*.

Part 2.1.4. Eliminate the word “best” as illustrated below.

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following comments and suggestions:

1. Requirement R2 Part 2.1 as written appears to only apply if the BA elected to document a set of Scenarios. If the intent is for Part 2.1 to also apply if a methodology is chosen instead, BC Hydro recommends that R2 be revised to clarify whether the expectations to have a base Scenario and stressed Scenarios due to 2.1.1 through 2.1.4 conditions would also need to be part of the methodology.

2. Requirement R2 Part 2.1.4 includes the word “best”. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the best information available at the time of Scenario development.

BC Hydro recommends that the word “best” be removed as “best” is not measurable or auditable.

3. Measure M2 as written ("Each Balancing Authority shall document the rationale for the Scenarios”) appears to set a new Requirement, i.e. document a rationale, in addition to R2, which only requires documentation of Scenarios (or method).

BC Hydro requests that the Measure M2 be revised to conform to the language of the Requirement R2.

4. Requirement R3 requires a BA to document one or more Operating Plan(s) (OP(s)) to implement in response to forecasted Energy Emergencies, Requirement R5 requires a BA to implement the OP(s) as documented in Requirement R3 and Requirement R6 requires a BA to review the OP(s) at least every 24 calendar months. These three together can be interpreted that the intent of Requirement R3 is for a BA to have a standing OP(s) that can be implemented for any forecasted Energy Emergency as opposed to specific OP(s) created once an individual Energy Emergency has been forecasted. This interpretation would also align with EOP-011-4 which requires a standing OP that is then implemented when an Energy Emergency happens. The technical rationale also implies a standing OP(s) as the wording mentions prior to forecasting Energy Emergencies. However, as Requirement R3 is not specific, another interpretation for Requirement R3 is that specific OP(s) are documented for each forecasted Energy Emergency after an Energy Emergency has been forecasted. This alternate interpretation would not align with Requirement R6 as there would be no standing OP(s) to review.

BC Hydro recommends that the drafting team clarify if the intent of Requirement R3 is for the BA to have a standing OP(s) which then, under Requirement R5 would be implemented for any forecasted Energy Emergency where specifics would be captured and which would align with Requirement R6; or if the intent is that the BA have a specific OP(s) for a forecasted Energy Emergency developed after an Energy Emergency is forecasted in which case Requirement R6 would need to be revised to remove the review of the OP(s) as the OP(s) would constantly be developed when a new Energy Emergency is forecasted.

If Requirement R3 is intended that OP(s) be created for specific forecasted Energy Emergencies, then if a BA has never had a forecasted Energy Emergency, they would not have an OP(s) under Requirement R3.

Regardless of which interpretation is chosen, as Requirement R3 does not specify a timeline for the BA to notify its RC of the OP(s), it's possible the OP(s) could have the RC notification be anytime (ex. notify RC of the forecasted Energy Emergency and OP(s) six months after the forecasted Energy Emergency). BC Hydro recommends revising Requirement R3 to include a timeline to notify the RC of the documented OP(s).

5. Requirement R6 references a BA's "applicable Reliability Coordinator", which can be subject to interpretation.

BC Hydro recommends that "applicable" be changed to "its" Reliability Coordinator which would align with the other Requirements as well as EOP-011.

6. BC Hydro notes that Requirement R6 includes providing the Near-term ERA process, Scenarios or methods to the applicable Reliability Coordinator. Therefore, the Reliability Coordinator would not see the Near-term ERA process, Scenarios or methods until potentially two years after they are documented. BC Hydro recommends documenting the reliability benefit of providing the Near-term ERA process, Scenarios or methods to the Reliability Coordinator as, as drafted, it is not timely and seems to be for information only.

7. Measure M6 requires each BA to "have evidence that it reviewed and documented its Near-term ERA process, Scenarios or methods, and Operating Plan(s) to its Reliability Coordinator". BC Hydro suggests that M6 requires a grammar check. Similarly, the VSL Table for R6 Severe VSL would require a grammar check.

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

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

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	
Document Name	
Comment	

Portland General Electric has two concerns with BAL-007 as currently drafted:

First, the Requirements in the current draft for BAL-007 appear to document the Standard assessments that are occurring throughout the industry today. It is unclear whether any new actions will need to be taken, other than additional documentation of what is already being done. This only serves the purposes of compliance audits and reduces the value the Standard sought to add in the first place.

Second, the SAR discusses the need for assessment of major regional or interconnection-wide disruptions, such as the loss of a major gas pipeline. This type of disruption could impact many Balancing Authorities and Reliability Coordinator areas simultaneously. In this situational example, each Balancing Authority potentially impacted by the outage would only be aware of the local impact, not the potential net regional impact. Each Balancing Authority would not know what responses other entities were taking because of the disruption. It is reasonable to expect that each Balancing Authority would assume that their own gas plant capacity (or variable energy resources if that is what is being assessed) could be replaced by going to the market, based on historical availability, without the total impact being covered as part of any one assessment. As stated in comments on the previous draft, the Balancing Authority is not an appropriate entity to rely on, or put the burden on, for interconnection-wide reliability assessments. Per the NERC webinar on 10/10/24, there would be value if BA's, RC's and other regional entities came together to perform such assessments, but that is not a Requirement of BAL-007. Today, some regional entities are already pursuing this type of assessment, and others are not. There is no reason to believe that BAL-007 will change this. For that reason, BAL-007 does not appear to address the primary concerns from the SAR.

Likes 0	
Dislikes 0	
Response	

TOP-003-7

5. The drafting team (DT) modified TOP-003-6 to ensure industry that Near-Term ERA type data can be requested. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

The information in TOP-003-7 R1.3.1, R1.3.2, R2.3.1 and R2.3.2 matches exactly that which must be developed by GOs for EOP-012-2, suggesting that generation plants are to forward this material to TOPs and BAs, who are then to make use of it. That exchange is not mandated by TOP-003-7, however, which says that TOPs and BAs shall have, "Provisions for notification of BES generating unit(s)…," i.e. TOP/BA-to-GO. Did you mean to call for GO-to-TOP/BA notification. i.e. from, not of?

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

The Requirement R1 of the proposed TOP-003-7 (Draft 1) requires the TOP to maintain documented specification for the data and information necessary for it to perform its Energy Reliability Assessments.

The currently adopted TOP-003-6.1 Requirement R1 does not reference Energy Reliability Assessments. This drafted change has not been identified in the red line version of the proposed TOP-003-7, it was not covered during the October 10, 2024 industry webinar, nor was this proposed change indicated in any other documentation.

BC Hydro recommends that the language of R1 be revised to remove Energy Reliability Assessments which would align with TOP-003-6.1 R1.

Likes 0	
Dislikes 0	
Response	

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	

BPA appreciates the effort made by the DT to make changes based on industry feedback. BPA has identified a few areas for improvement in this draft. Please see comments below.

BPA identified that R1 (applicable to the TOP) includes language pertaining to 'Energy Reliability Assessments'. The ERA language was included in TOP-003-7 but not redlined as new from previous versions of TOP-003. BPA recommends the drafting team remove this language as Energy Reliability Assessments will be applicable to the BA, as per BAL-007-1, and included under R2 and R4 of TOP-003-7.

BPA seeks clarity regarding the DT's inclusion of 'Near-Term' pertaining to ERA in TOP-003-7 R2 and R4. BPA has concerns that including a specific assessment term in the requirement language could potentially require standard revisions if any future assessments (or new terms/definitions) that may require data per TOP-003 are created. BPA offers a potential language revision for R2 and R4:

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions ***(e.g., Energy Reliability Assessments, etc.)*** and Real-time monitoring. The data specification shall include, but not be limited to:

R2.1. A list of data and information needed by the Balancing Authority to support its analysis functions ***(e.g., Energy Reliability Assessments, etc.)*** and Real-time monitoring including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions ***(e.g., Energy Reliability Assessments, etc.)*** and Real-time monitoring.

Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	No
Document Name	
Comment	

R1 and R2 seem duplicative and ripe for error if you have shared responsibilities for the same information with the TO and BA. The applicability to the TO is also confusing as BAL-007 is specific to the BA. It is also unclear how compliance is evaluated - is NERC or the TO/BA identifying the relevant entities that have data and information required by the TO and/or BA's Operational Planning Analyses, Real-time monitoring, and Energy Reliability Assessments?

Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments on TOP-003-6's proposed updates.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy supports the changes made to TOP-003-6.	
Likes 0	
Dislikes 0	
Response	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
There is an accidental reference to Energy Reliability Assessments in TOP-003-7 in R1, even though the BAL-007 data is not applicable to TOPs. As mentioned in the NERC project 2022-03 Energy Assurance Industry Webinar on 10/10/2024, this reference will be removed on the next draft.	
Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	

Answer	Yes
Document Name	
Comment	
EEI supports the changes made to TOP-003-6.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes
Document Name	
Comment	
TOP-003-7 R1 is only applicable to the TOP functions. It's not indicated as a redline but "Energy Reliability Assessments" were added to the R1 main requirement. This should be removed as it looks like it was added by mistake when the Near-Term Energy Assessments were added to the BA Requirements.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 5	
Likes 0	
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	

Answer	Yes
Document Name	
Comment	
APS agrees with the proposed changes to TOP-003-7.	
Likes 0	
Dislikes 0	
Response	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	

Comment	
WEC Energy Group supports the changes made to TOP-003-6.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to TOP-003-6.	
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	
The proposed changes are minimal and will cause no undue burden on Balancing Authorities.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The response if provided on behalf of Exelon representing Segments 1 and 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 the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Bryan Bennett - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	

SDG&E needs to see what additional data, if any, will be needed by the CAISO as our BA so that they can perform the new Near-Term Energy Reliability Assessment.

Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Anna Lavik - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 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	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF

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

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
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	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Fausto Serratos - Los Angeles Department of Water and Power - 3

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE noticed that TOP-003-7 Requirement R1 include Energy Reliability Assessments in the documented specifications that the TOP shall maintain. BAL-007-1 requires BAs to conduct and Energy Reliability Assessment, but there does not appear to be a parallel requirement in TOP-003-7 for TOPs. Is it the intent of the SDT to require TOPs also conduct a Energy Reliability Assessment? Subpart 1.1 does not mention Energy Reliability Assessments. Texas RE is also concerned that the TOPs do not have the necessary system-wide level information for conducting Energy Reliability Assessments and would potentially be duplicating the work of the BAs.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	
Document Name	

Comment

Should TOP-003-7 take into account the scenario where a Near-Term ERA is determined to be not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s) as per BAL-007-1 R1.3.1?

R1 of TOP-003-6.1 does not request maintaining documented specifications for data and information necessary for it to perform Energy Reliability Assessments, yet it has been added to R1 and is not redlined. Was it meant to be added to this requirement in this standard or was it meant for BAL-007-1? If meant for TOP-003-7, should Energy Reliability Assessments be listed in R1.1 as well given it is a sub requirement of R1?

Likes 0	
Dislikes 0	

Response

TOP-003-7

6. The DT drafted the TOP-003-7 implementation plan allowing 18 months to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Bryan Bennett - Sempra - San Diego Gas and Electric - 3

Answer	No
Document Name	

Comment

Unknown at this time. SDG&E needs to see what additional data, if any will be needed by the CAISO before we are able to determine if 18 months will be sufficient time to become compliant.

Likes 0	
Dislikes 0	

Response

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

Answer	No
Document Name	

Comment

IID believes that the implementation plan for TOP-003-7 should be the same 24-months implementation schedule as BAL-007-1.

Likes 0	
Dislikes 0	

Response

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

EEI does not support the proposed Implementation Plan for TOP-003-7 because it was not appropriately aligned with the Near-Term Energy Reliability Assessment definition Implantation Plan. EEI notes that this term will not go into effect until 6 months after TOP-003-7. Given this term is used in both

Requirements R2 and R4 the implementation plan should not be approved until the implementation plan for this term is harmonized with the proposed implementation plan for TOP-003-7.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	No
Document Name	
Comment	
Ameren supports the comments provided by MISO:	

There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that do not become effective until 24 months following FERC approval. MISO proposes the Standard Drafting Team align the two so that they become effective at the same time.

Likes 0	
Dislikes 0	

Response

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	No
Document Name	

Comment

More information is needed to clarify TO and BA responsibilities, the documentation and evidence for required data and information and compliance obligations, in general.

Likes 0	
Dislikes 0	

Response

Stephanie Kenny - Edison International - Southern California Edison Company - 6

Answer	No
Document Name	

Comment

See EEI Comments

Likes 0	
Dislikes 0	

Response

Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin

Answer	No
Document Name	

Comment

ITC agrees with EEI's comments.

Likes 0	
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	

APS agree with the following EEI comments:

EEI does not support the proposed Implementation Plan for TOP-003-7 because it was not appropriately aligned with the Near-Term Energy Reliability Assessment definition Implantation Plan. EEI notes that this term will not go into effect until 6 months after TOP-003-7. Given this term is used in both Requirements R2 and R4 the implementation plan should not be approved until the implementation plan for this term is harmonized with the proposed implementation plan for TOP-003-7.

Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	

Black Hills Corporation would like to see the Implementation Period changed to 24 months to align with the effective date of the definition for the Near-Term Energy Reliability Assessment.

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	

Comment	
There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that don’t become effective until 24 months following FERC approval. NV Energy would recommend that the terms that are currently defined in BAL-007 have an implementation date prior to TOP-003-7 becoming effective.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 6	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments on the necessity to coordinate this standards effective date with the effective date of the new defintion in BAL-007.	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	

Answer	No
Document Name	
Comment	

There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that don’t become effective until 24 months following FERC approval. ISO.RTO Council Standards Review Committee (IRC SRC) proposes the Standard Drafting Team align the two so that they become effective at the same time.

Likes 0	
Dislikes 0	

Response

Casey Perry - PNM Resources - 1,3 - WECC,Texas RE

Answer	No
Document Name	
Comment	

PNM does not support an 18 month implementation timeline for TOP-003-7 due to the Near-Term Reliability Assessment definition will not go into effect until 24 months after FERC approval. PNM would support a 24 month implementation of TOP-003-7. PNM also supports EEI's comments regarding question 6.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	
Comment	

Tri-State Generation and Transmission agrees with the MRO NSF Submitted Comments.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	No
Document Name	
Comment	
TOP-003 goes into effect in 18 months versus BAL-007's 24 months, but uses the new glossary term from BAL-007 "Near-Term Energy Reliability Assessment." This means that TOP-003 would be effective using a NERC glossary term that **is not effective** yet.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
The implementation plan for TOP-003-7 is 18 months following FERC approval. The implementation plan for BAL-007 is 14 month following FERC approval. TOP-003-7 refers to definitions in BAL-007. It is recommended that the definitions in BAL-007 are implemted prior to implantation of TOP-003-7.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that don't become effective until 24 months following FERC approval. MRO NSRF would recommend that the terms that are currently defined in BAL-007 have an implementation date prior to TOP-003-7 becoming effective.	
Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that don't become effective until 24 months following FERC approval. MRO NSRF would recommend that the terms that are currently defined in BAL-007 have an implementation date prior to TOP-003-7 becoming effective.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy does not support the proposed TOP-003-7 Implementation Plan but does support the following EEI response: EEI does not support the proposed Implementation Plan for TOP-003-7 because it was not appropriately aligned with the Near-Term Energy Reliability Assessment Definition Implantation Plan. EEI notes that this term will not go into effect until 6 months after TOP-003-7. Given this term is used in both Requirements R2 and R4 the implementation plan should not be approved until the implementation plan for this term is harmonized with the proposed implementation plan for TOP-003-7.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
The Implementation Plan for TOP-003-7 is not aligned with the Near-Term Energy Reliability Assessment Definition Implantation Plan. This term will not go into effect until 6 months after TOP-003-7. Given this term is used in both Requirements R2 and R4 the implementation plan should not be	

approved until the implementation plan for this term is in parallel with the proposed implementation plan for TOP-003-7. FirstEnergy asks the DT to clarify.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation 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 submitted comments by EEI.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon does not oppose 18 months to implement TOP-003.

Exelon supports the concerns stated in the EEI comments regarding the opportunity to improve alignment between the implentation of the two standards.

The response if provided on behalf of Exelon representing Segments 1 and 3

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

The proposed implementation timelines are sufficient for entities to both identify any additional data needed, and to communicate to entities the additional data request.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Fausto Serratos - Los Angeles Department of Water and Power - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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	

Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,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	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
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	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, 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	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
There is a mismatch in the implementation dates for TOP-003-7 and definitions in BAL-007 that come into effect at a later date than the TOP-003-7 standard.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro is unable to support the implementation plan at this time as additional clarifications to Requirements are needed prior to assessing the implementation plan.	
Likes 0	
Dislikes 0	
Response	

TOP-003-7

7. The DT proposes that the modified TOP-003-7 meets the Standards Authorization Request 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.

Jessica Lopez - APS - Arizona Public Service Co. - 3

Answer	No
Document Name	
Comment	
There is no technical justification of the reliability-related benefits and costs for this project.	
Likes 0	
Dislikes 0	
Response	

Bryan Bennett - Sempra - San Diego Gas and Electric - 3

Answer	No
Document Name	
Comment	
Unknown at this time. SDG&E needs to see what additional data, if any will be needed by the CAISO before we are able to determine what the costs will be to provide the data.	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	No
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments on TOP-003-7's cost effectiveness	
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	
Yes, there should be minimal impact on entities who must provide additional data to the Balancing Authorities under these proposed revisions to the Standard.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The response if provided on behalf of Exelon representing Segments 1 and 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 the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF	
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	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
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	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Fausto Serratos - Los Angeles Department of Water and Power - 3

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

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 will not submit comments on the cost effectiveness of the proposed TOP-003-7 Reliability Standard.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

TOP-003-7

8. Provide any TOP-003-7 additional comments for the SDT to consider, if desired.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT notes that TOP-003-7 Requirement R1 includes a reference to Energy Reliability Assessments. This reference appears to be unnecessary, as R1 is limited to Transmission Operator data specifications, and BAL-007-1 is not applicable to Transmission Operators.	
Likes 0	
Dislikes 0	
Response	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company supports the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	

Response	
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	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	EEI Near Final Draft Comments _ Project 2022-03 BAL-007 & TOP-003 Rev 0c _ 11_01_2024 (1).docx
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
NPCC RSC supports the project.	
Likes 0	
Dislikes 0	
Response	

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
Please correct the numbering in the subsections of the “C. Compliance section” they should read 1.1 to 1.3 instead of 4.1.1 to 4.1.3.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
Evidence Retention sections needs to be modified to add references to “Near-Term Energy Reliability Assessments”. “Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions**, Real-time monitoring, and Near-Term Energy Reliability Assessments** in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit.” “Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority’s analysis **, Real-time monitoring, and Near-Term Energy Reliability Assessments** in accordance with Requirement R4 and Measurement M4.”	
Likes 0	
Dislikes 0	
Response	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	
Comment	
N/A	
Likes 0	

Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF	
Answer	
Document Name	
Comment	
N/A	
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	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	

The draft TOP-007-1 only includes the Near-Term ERA definition, which relies on the new ERA proposed definition. The proposed implementation plan indicates that the newly proposed definitions become effective “when the proposed standard is approved", which may imply that ERA would only become effective upon approval of BAL-007-1. If BAL-007-1 is not approved on or before TOP-003-7 is approved, the Near-Term ERA definition may not be enforceable.

BC Hydro suggests that the Implementation Plan be revised to ensure that the new ERA and Near-Term ERA definitions become effective at the same time.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Consideration of Comments

Project Name:	2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 TOP-003-7 and Draft 3 BAL-007-1
Comment Period Start Date:	9/19/2024
Comment Period End Date:	11/4/2024
Associated Ballot(s):	2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 Implementation Plan IN 1 OT 2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 TOP-003-7 IN 1 ST 2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 AB 3 ST 2022-03 Energy Assurance with Energy-Constrained Resources Implementation Plan AB 3 OT

There were 54 sets of responses, including comments from approximately 167 different people from approximately 103 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Director, Standards Development Jamie Calderon (via email) or at (404) 446-9647.

Questions

BAL-007-1 Near-term ERAs

1. The drafting team (DT) modified BAL-007-1 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

BAL-007-1 Near-term ERAs

2. The DT updated the implementation plan to allow for 24 months for BAL-007-1 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

BAL-007-1 Near-term ERAs

3. The DT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request 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.

BAL-007-1 Near-term ERAs

4. Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

TOP-003-7

5. The drafting team (DT) modified TOP-003-6 to ensure industry that Near-Term ERA type data can be requested. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

TOP-003-7

6. The DT drafted the TOP-003-7 implementation plan allowing 18 months to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

TOP-003-7

7. The DT proposes that the modified TOP-003-7 meets the Standards Authorization Request 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.

TOP-003-7

8. Provide any TOP-003-7 additional comments for the SDT to consider, if desired.

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO

				Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
				George Brown	Pattern Operators LP	5	MRO
				Larry Heckert	Alliant Energy (ALTE)	4	MRO
				Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
				Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
				Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
				Michael Ayotte	ITC Holdings	1	MRO
				Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
				Peter Brown	Invenergy	5,6	MRO
				Angela Wheat	Southwestern Power Administration	1	MRO

					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group, Inc.	3	RF
					Michelle Hribar	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
					Candace Morakinyo	WEC Energy Group, Inc.	4	RF
Independent Electricity System Operator	Helen Lainis	2		IRC SRC	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Gregory Campoli	New York Independent System Operator	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Charles Yeung	SPP	2	SERC
					Elizabeth Davis	PJM	2	RF

ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kris Carper	Arizona Electric Power Cooperative, Inc.	1	WECC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
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
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC

Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Travis Grablander	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC

					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC

Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
Vijay Puran	New York State Department of Public Service	6	NPCC
David Kiguel	Independent	7	NPCC
Joel Charlebois	AESI	7	NPCC
Joshua London	Eversource Energy	1	NPCC
Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
Joel Charlebois	AESI	7	NPCC
John Hastings	National Grid	1	NPCC
Erin Wilson	NB Power	1	NPCC
James Grant	NYISO	2	NPCC
Michael Couchesne	ISO-NE	2	NPCC
Kurtis Chong	IESO	2	NPCC
Michele Pagano	Con Edison	4	NPCC
Bendong Sun	Bruce Power	4	NPCC

					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Nicolas Turcotte	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Shannon Mickens	Shannon Mickens		MRO,SPP RE,WECC	SPP RTO	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Mia Wilson	Southwest Power Pool Inc.	2	MRO
					Eddie Watson	Southwest Power Pool Inc.	2	MRO
					Erin Cullum	Southwest Power Pool Inc.	2	MRO

					Jonathan Hayes	Southwest Power Pool Inc.	2	MRO
					Jeff McDiarmid	Southwest Power Pool Inc.	2	MRO
					Scott Jordan	Southwest Power Pool Inc	2	MRO
					Mason Favazza	Southwest Power Pool Inc	2	MRO
					Sherri Maxey	Southwest Power Pool Inc.	2	MRO
					Josh Phillips	Southwest Power Pool Inc.	2	MRO
Western Electricity Coordinating Council	Steven Rueckert	10		WECC Entity Monitoring	Steve Rueckert	WECC	10	WECC
					Curtis Crews	WECC	10	WECC
Public Utility District No. 1 of Chelan County	Tamarra Hardie	6		CHPD	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Santee Cooper	Vicky Budreau	3		Santee Cooper	Lachelle Brooks	Santee Cooper	1,3,5,6	SERC
					Diana Scott	Santee Cooper	1,3,5,6	SERC

BAL-007-1 Near-term ERAs

1. The drafting team (DT) modified BAL-007-1 based on industry feedback. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	

R2.1.1-R2.1.3 lack specificity, creating risk that the scenarios postulated by BAs will fall short of the actual challenges that may be faced. This is especially the case when applying the rule, “The Near-Term ERA process shall account for…Forecasted or assumed Demand profiles.” PJM’s forecast for Winter Storm Elliott was low by 12 GW; ERCOT missed by 10 GW. BAL-007 ERAs may have little value until the forecasting state of the art advances enough to eliminate this problem.

A far more secure approach is to place more emphasis on R2.1.4, historical precedents. That is, require that ERCOT study a repeat of Winter Storm Uri, require that PJM study a repeat of the record-setting cold of January 1994, etc. The weather data for the plants we had in Texas in 2021 showed that Uri and the deep freeze event of Dec. 1989 were remarkably similar. There is no need for guesswork or statistical studies; just adopt the view that what happened before will eventually occur again.

BAL-007 should also require sufficient scenarios to address the changing mix of generation, e.g. a deep freeze with high wind for conventional plants, an ice storm for wind farms, and combination events (such as Winter Storm Uri).

Above all else, BAL-007 should make it clear that limiting the scenarios being studied to the EOP-012 ECWT is not sufficient. Recent generation capacity emergencies have generally involved temperatures well below the ECWT, plus high winds.

Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	

Thank you for your comment. A standard provides industry with the bare minimum of what is required to meet the standard. Balancing Authorities should use the most recent data and entities are welcome to go above and beyond the requirements of standard. Modification of the standard was made based on industry feedback.

Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

BPA appreciates the effort made by the Drafting Team (DT) to make changes based on BPA's comments during the previous comment period. BPA sees the value of the changes made but has identified an area for improved clarity in this draft. Please see comments below.

To allow for more defined coordination with other BAs, and to meet the intent of the "…Jointly with other Balancing Authorities…" language used throughout the BAL-007-1 requirements, BPA recommends the creation of a new term and definition similar to Reserve Sharing Group (RSG) in the NERC Glossary of Terms, as a NERC Compliance Registration (as seen with RSG, FRSG, etc.), and revisions to BAL-007-1 Requirement language, in order to allow an entity to be the 'Responsible Entity' for multiple BAs.

The intent of this new term and registration is to be included in BAL-007-1 in the applicability section and/or the Requirements to provide similar clarity to the placement of language used in BAL-002 and BAL-003, as seen below. BPA believes adding this to the standard would create continuity with other defined terms and registration types and clearly execute the intent for BAs to 'jointly' meet the reliability objectives outlined in BAL-007-1.

Section 4, Applicability of BAL-002-3:

4.1.1.1. "A Balancing Authority that is a member of a Reserve Sharing Group is the Responsible Entity only in periods during which the Balancing Authority is not in active status under the applicable agreement or governing rules for the Reserve Sharing Group.

4.1.2. Reserve Sharing Group

Section 4, Applicability of BAL-003-2:

4.1.1.1. Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Frequency Response Sharing Group, in which case, the Frequency Response Sharing Group becomes the responsible entity. 4.1.2. Frequency Response Sharing Group **BAL-003-2, Requirement R1**: R1. "Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall…" BPA believes its recommendations in question 1 align with benchmark 1, 8, and 10 of the 'Ten Benchmarks of an Excellent Reliability Standard' as referenced in the NERC Standards Process Manual, Section 4.4.2, 'Draft Reliability Standard'. BPA also views its recommendations as 'in scope' of this project as noted in bullet one of the SAR: "…create defined terms as needed…" Additionally, BPA agrees with the Near-Term ERA Definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The drafting team does not find developing a new term to capturing Reserve Sharing Group is appropriate at this time. It is clearly captured with BAL-007 that multiple BAs can work together and could create groups similar to Reserve Sharing Groups without a specific NERC-defined group. Other Regions may use different groups of multiple BAs that are called something other than "Reserve Sharing Groups;" therefore, the DT feels that multiple BAs is the appropriate path forward. Joint BAs enables BAs to work with other BAs to develop what is needed for BAL-007.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

The language in the current draft 3 BAL-007-1 R1 will allow entities to perform no evaluation of forecasted Demand and resource capabilities for self-determined time period(s). The language of BAL-007-1, draft 2 is preferred as compared to draft 3.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The draft standard was updated based on industry feedback, which is reflected in draft 3. Draft 3 also provides flexibility for entities, which was a major theme in the past round of comments.

Jessica Lopez - APS - Arizona Public Service Co. - 3

Answer	No
Document Name	

Comment

The requirements in BAL-007-1 Draft 3 identify that “Each Balancing Authority shall, individually or jointly with other Balancing Authorities” perform/comply with the standard, however, this statement creates ambiguity and does not clearly specify ownership of compliance. To enhance clarity and accountability, it is essential to delineate the ownership and responsibility for compliance within the requirements more precisely. This can be achieved by specifying which functional entities are accountable for each compliance aspect and detailing the actions they must take. Such specificity facilitates better adherence to the requirements and clearly specifies ownership of compliance. In addition, the Measurement criteria should specify that each Balancing Authority shall have evidence of compliance. If the requirements include more than one BA or group of BAs, the measurements should be clear as to compliance ownership and mirror each requirement’s language.

For example, in BAL-002-WECC-3, the Functional Entities Applicability section 4.1, the Standard clearly defines who the responsible entity is for reporting:

4.1.1 Balancing Authority

4.1.1.1 The Balancing Authority is the responsible entity unless the Balancing Authority is a member of a Reserve Sharing Group, in which case, the Reserve Sharing Group becomes the responsible entity.

4.1.2 Reserve Sharing Group 4.1.2.1 The Reserve Sharing Group, when comprised of a Source Balancing Authority, becomes the source Reserve Sharing Group. 4.1.2.2 The Reserve Sharing Group when comprised of a Sink Balancing Authority becomes the sink Reserve Sharing Group. There is concern that as BAL-007-1 Draft 3 includes each BA individually or jointly with other BAs, more specifically "jointly with other BAs" does not explicitly define who the responsible entity is for reporting. Since it is not written, a Balancing Authority may be under the impression that the group is the responsible entity for reporting and not the Balancing Authority themselves. With the inclusion of additional parties, it would be best served to explicitly define who the entity responsible is for compliance with the Standard.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The DT believes that "Each Balancing Authority" clearly puts the responsibility of meeting standard on each BA even if they perform activities to meet the standard together. The DT does not find developing a new term to capturing Reserve Sharing Group is appropriate at this time. It is clearly captured within BAL-007 that multiple BAs can work together and could create groups similar to Reserve Sharing Groups without a specific NERC-defined group. Other Regions may use different groups of multiple BAs that are called something other than "Reserve Sharing Groups;" therefore, the DT feels that multiple BAs is the appropriate path forward. Joint BAs enables BAs to work with other BAs to develop what is needed for BAL-007.

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	No
Document Name	
Comment	

RF has a concern with 1.3.1. An energy assessment should be required for each operating day. The intent of the standard is to conduct an energy assessment to identify a possible energy shortfall, by allowing an overly broad opt out option the intent of the standard will be lost. An applicable study should be on hand for each operating day (although performing a study periodically as proposed is acceptable).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard does not preclude an entity from completing energy assessments each operating day. It is up to the entity to determine when their energy assessments should be completed. In addition, the standard requires specific timeframes based on 1.3.2 and for a documented method to determine when risk is low of an Energy Emergency. Lastly, BAL-007 standard is not looking at next day. It is looking for several days out. The goal is to be prepared for next few days' to weeks' operations.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
The flexibility and lack of defined methodology for defining time periods and criteria for identifying low risks is understandable, and perhaps appreciated, due to regional and system differences between entities. However, the lack of specificity creates concerns about how NERC will judge the proposed methodologies and criteria and how compliance will be measured/assessed. Creating a 5-day plan will be very specific to conditions that have the potential to change, limiting the ability of our teams to act appropriately if they feel tied to the plan. Conversely, plans that are as long as 6 weeks are likely lacking timely enough data for decision making. Additionally, the listed scenarios in R2 may not always be relevant and it's unclear whether each assessment must include an evaluation	

of listed scenarios.
It is reasonable for to expect a level of preparedness planning when the scenarios in R2 are forecast but an action plan for mitigating risk is more what's needed rather than an operating plan to be implemented.
The ability to plan with other balancing authorities is appreciated.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. If you are concerned with the development of your methodology, the DT encourages you to review it with your RC and your respective Region to get feedback.

The language was drafted to provide entities with flexibility allowing an entity to pick what is appropriate for you between 5 days and 6 weeks.

An entity must review each scenario laid out in Requirement R2. These are the bare minimum required of entities when complying with BAL-007-1.

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 and BANC

Answer	No
Document Name	

Comment

We understand the purpose of the proposed BAL-007-1 reliability standard and Near-term Energy Reliability Assessment (ERA), however, a Near-term ERA is only necessary for special operating conditions which may be less than 10% of the time for many Balancing Authorities (BAs). Under normal operating conditions when the load is not high and resource availability is good, the Outage Coordination process in IRO-017-1 and Operations Planning process in TOP-002-4 would cover the desired contents of the Near-Term ERA, so the assessment is

not needed during normal operating conditions. The proposed BAL-007-1 requires too much procedural burden during normal operating conditions. We suggest the Drafting Team revise Requirement R1 to reverse the order so that BAs document a process that accounts for ***when*** to conduct a Near-Term ERA first. Criteria for ***when*** BAs are required to conduct a Near-Term ERA should be listed as the first sub-requirement (e.g. Requirement R1.1) so that 90% of the time BAs do not have to complete one. We agree with the details listed in Requirement R1.1.1 through R1.1.4. for what must be accounted for and the duration of the Near-Term ERA in Requirement R1.2., however, these should be listed after conditions for ***when*** a Near-Term ERA is required. As currently written, the methodology for ***when*** a Near-Term ERA is not necessary because there is a low-risk of an Energy Emergency occurring is included down in Requirements R1.3.1 and R1.3.2. Since this is where BAs will operate more than 90% of the time, the conditions triggering a Near-Term ERA should be listed first in Requirement R1 and not last. In addition, we suggest the Drafting Team simplify the original Requirement R1.3 and make it the new R1.1 as follows: R1.1 The Near-Term ERA process shall specify the operating conditions for which the Balancing Authority will conduct a Near-Term ERA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The draft standard was updated based on industry feedback, which is reflected in draft 3. Draft 3 also provides flexibility for entities, which was a major theme in the past round of comments.	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	No
Document Name	
Comment	
The Los Angeles Department of Water and Power (LDWP) appreciates the opportunity to provide feedback on BAL-007-1. LDWP notes that many utilities, including those within our Balancing Authority Area, already comply with rigorous planning requirements set forth by state or local regulatory authorities, suggesting that the additional planning directives in BAL-007-1 may be potentially redundant. If the	

intent is to improve coordination with the Reliability Coordinator (RC) during energy-constrained events, LDWP recommends that the Standard emphasize this goal directly, rather than imposing new planning mandates. This focused approach would prevent duplicating existing regulatory obligations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The standard does not preclude an entity from completing energy assessments each operating day. It is up to the entity to determine when their energy assessments should be completed. In previous drafts, it was proposed that the BA and RC complete back and forth coordination. Industry clearly explained that they felt this was an administrative burden based on the back and forth requirements drafted. At this point in the process, the DT feels it is important that the RC is made aware of the assessments completed. The RC may respond and if back and forth is completed by both functional entities, that additional step would be encouraged in the process.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT recommends that Requirement R1, Part 1.1 be revised to clarify that the Near-Term ERA process must account for the listed items as they may apply during the time period that any given Near-Term ERA assesses, not as generic items. ERCOT likewise recommends that Requirement R1, Part 1.1.4 be revised to clarify that it refers to BES transmission constraints known at the time the Near-Term ERA is performed. ERCOT further recommends that Requirement R1, Part 1.3 be clarified by replacing “the frequency with which the Balancing Authority will conduct Near-Term ERAs” with “how often the Balancing Authority will conduct Near-Term ERAs.”	

To further clarify the Balancing Authority's discretion in developing Scenarios under Requirement R2, ERCOT recommends that Part 2.1 be revised as follows: " . . . (ii) other Scenarios that stress the system **to the degree determined and documented by the Balancing Authority** due to the following conditions . . ."

ERCOT also recommends that Part 2.1.4 be revised to indicate that it refers to historical conditions from the time of year that the Near-Term ERA in question is assessing, thereby clarifying that responsible entities are not (for example) required to consider historical summer conditions during a Near-Term ERA that assesses a time period in the winter.

ERCOT appreciates the drafting team's revisions to Requirements R3 and R5; however, ERCOT is concerned that these Requirements could be read to require potentially unnecessary actions based on assessments that rely on incomplete information (such as information regarding fuel supply chains) to examine events that have a very low probability of occurring. Consequently, ERCOT recommends that Requirements R3 and R5 be removed from BAL-007 so that entities can focus on dialing in their ERAs under this first version of BAL-007. If the requirements are retained, ERCOT recommends that Requirement R3 be revised to more explicitly indicate that Operating Plans are only required to be documented for forecasted EEA2 and EEA3 circumstances, consistent with Requirement R5.

Finally, ERCOT recommends that "documented" be replaced with "provided" in Measure M6 to better align with the language used in Requirement R6.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The standard was drafted at a level that allows flexibility among entities. During the drafting of this standard, the DT discovered that entities complete the 'how' in different ways. ERCOT can be as specific in its process as to how it is addressing the 'how' of the requirements.

The focus of Requirement R1 Part 1.1.4. is on Known Bulk Electric System (BES) Transmission constraints that limit the ability of generation to deliver their output to Load. Requirement R1 has been drafted at a generic level to provide flexibility on what works best for ERCOT. Based on comments received over the past many drafts, the DT does not feel it needs to provide more specificity. You can put your known BES transmission constraints within your process.

Requirement R1 focuses on you drafting out your process. You can be specific with how often you will conduct your Near-Term ERA in your process documentation. The flexibility is there for you to add something to the extent of "if deemed necessary."

The language in Requirement R2 is flexible enough for an entity to add to the degree determined and documented by the BA within its process of R1. In addition, the language is clear that Operating Plans are required for forecasted EEAs. Operating plans are the responses needed for forecasted EEAs.

While it is the intent for BAs to perform the ERA, jointly or individually, they are each responsible for documenting their scenarios and operating plans. The DT feels it is clear that this is what is required in R3 and R5.

Please see the updated measure M6.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments on BAL-007-1's proposed draft.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy supports the proposed changes made to BAL-007-1, Draft 3.	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM agrees with the changes to BAL-007-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 1	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI on question 1.	

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the proposed changes to BAL-007-1, Draft 3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed changes made to BAL-007-1, Draft 3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The response if provided on behalf of Exelon representing Segments 1 and 3	
Likes 0	
Dislikes 0	

Response	
Thank you.	
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 submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Lavik - Puget Sound Energy, 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	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 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	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
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	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE recommends using consistent verbiage for maintaining documented processes/specifications in BAL-007-1 and TOP-003-7. BAs and TOPs should be documenting and maintaining the processes and specifications. Texas RE recommends the following revisions in BAL-007-1 Requirements R1, R2, and R3: R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities**, maintain a documented process** for conducting Near-Term Energy Reliability Assessments (ERA). R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, **maintain a documented set** of Scenarios, or a method for developing Scenarios, for use in performing Near-Term ERAs. In Requirement R3, Texas RE is concerned that there is no limit associated with the probability of the risk level for documenting the operating plan(s). BAs should have the option to define the probabilistic threshold for declaring the Energy Emergency based on the simulations. It may be administratively cumbersome to document Operating Plan(s) for each ERA simulation for which the simulations indicate a low probability of an Energy Emergency. The BAs should define the probabilistic risk threshold limit based on their system conditions/scenarios (for example, if the probability of declaring Energy Emergency is less than X%, BAs should not have to document any Operating Plan(s)).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see Requirement R6, which requires "Each Balancing Authority shall, individually or jointly with other Balancing Authorities, review, update, as necessary, and provide to the applicable Reliability Coordinator its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3, at least once every 24 calendar months." The Balancing Authorities are required to define and document their operating plans which include any thresholds by which they will implement. There is flexibility in how the BA develops its operating plans, but they must implement operating plans based on EEA and	

scenarios. The DT does not believe that this precludes the use of probabilistic methods or risk of EEA for forecasted EEAs. The BA can define this in the BA's documented process.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
WECC voted Affirmative, but suggests the DT consider the following: Requirement R2 provided the BA (or joint BAs) to either document a set of Scenarios OR a **method** for developing Scenarios however Requirement R2 Part 2.1 only describes a "set of Scenarios" and does not mention "method". Suggest changing language to 2.1 "The set of Scenarios, **or the method for developing Scenarios** must include…." Requirement R3 should pluralize Reliability Coordinator as the BAs may very well have different Reliability Coordinators but intend to use the same Operating Plan(s). Requirement R6 should delineate the efforts of reviewing, updating, and providing the materials listed. A Near-Term ERA, by definition is Near-Term and will be reviewed and updated in a much shorter timeframe than 24 calendar months. Operating Plans are similar in nature in that they can cover a short time period. Perhaps the process documentation (Near-Term ERA document, Scenario method, methodology for not doing a Near Term ERA—which is not mentioned here) should be provided but the outputs need a more realistic time period for provision to the RC.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. If you are concerned with the development of your methodology, the DT encourages you to review it with your RC and your respective Region to get feedback. The language was drafted to provide entities with flexibility allowing an entity to pick what is appropriate for you between 5 days and 6 weeks. An entity must review each scenario laid out in Requirement R2. These are the bare minimum required of entities when complying with BAL-007-1.	

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
For an entity whose generation is mostly reservoir-based hydro, the "near-term energy reliability assessment" horizon does not ensure reliability. Reliability is rather achieved on an annual and multi-annual horizon where water consumption, water levels and adequate storage are analyzed. In the near-term, refinement of what was planned in the long term is what occurs. In the case where an entity has full control over the reservoir, the notion of fuel supply, energy risk and energy emergency is low because this type of reservoir-based hydro is not a constrained resource. Is the new R1.3 meant to cover this scenario?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R1 focuses on you drafting out your process. You can be specific with how often you will conduct your Near-Term ERA in you process documentation. The flexibility is there for you to add something to the extent of "if deemed necessary." Yes. The new R1.3 is meant to cover this scenario as well as the Near-term ERA is meant to support the refinement of what long-term planned.	

BAL-007-1 Near-term ERAs

2. The DT updated the implementation plan to allow for 24 months for BAL-007-1 to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT appreciates the revised implementation timeline; however, ERCOT notes that entities are developing improvements to internal processes to improve energy capabilities for the operations planning horizon while these new NERC requirements are still being finalized. It is unknown at this time what the impacts of the new requirements will be, but resources will be needed to fully integrate and implement the NERC standards with internal processes. Consequently, while ERCOT appreciates the updates to the implementation plan, ERCOT requests that the implementation plan be further revised to allow at least 36 months for the implementation of all Requirements in BAL-007-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. With the removal of the administrative type requirements from the last draft, the DT did not feel that 36-months had adequate justification for development, implementing, and maintaining of what is required in BAL-007-1. Therefore. The DT feels that 24 months suffices.	
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 submitted comments by EEI.	

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
If this Standard becomes enforceable, a 24-month implementation timeline would provide sufficient time for compliance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The response if provided on behalf of Exelon representing Segments 1 and 3	
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	
Yes, limiting the proposed BAL-007-1 to Balancing Authorities makes the 24-month implementation reasonable.	
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 updated implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes

Document Name	
Comment	
"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the proposed updated implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	

See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
APS agrees with the updated Implementation Plan to allow for 24 months for BAL-007-1 to become compliant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 2	
Likes 0	

Dislikes 0	
Response	
Please see the DT's response to EEI.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	
PNM agrees with the 24 month implementation timeline.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE noticed there is no Effective Date header as is typical in other implementation plans.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See updated implementation Plan.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	

Answer	Yes
Document Name	
Comment	
Duke Energy supports the proposed updated implementation plan.	
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	
FirstEnergy has no comments on BAL-007-1's implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,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	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
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	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
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	
Donald Lock - Talen Generation, LLC - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, 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	
Anna Lavik - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	

Answer	
Document Name	
Comment	
BC Hydro is unable to support the implementation plan at this time as additional clarifications to Requirements are needed prior to assessing the implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

BAL-007-1 Near-term ERAs

3. The DT proposes that the newly proposed BAL-007-1 meets the Standards Authorization Request 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.

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
There was no cost/benefit study to show this is a cost-effective approach. It appears that BAs will have to conduct assessments that they were never intended to do, and they will have to acquire the specialized skills needed.	
Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Thank you for your comment. The white paper released in December 2020 expressed the importance of ensuring energy adequacy with energy constrained resources. The problem statement identified that unassured fuel supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, can result in insufficient amounts of energy on the system to serve electrical demand and ensure the reliable operation of the Bulk Power System (BPS) throughout the year. Based on the importance of the above listed problem statement, BAL-007 ensures that BAs assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon. Based on the importance of this risk, the DT feels the requirements are at an adequate level to achieve the reliability benefits in a cost-effective manner. In addition, please see technical justification in the SAR. Lastly, this is why questions are asked to industry with regards to the cost implication with regards to the requirements being drafted. This is the time for industry to provide feedback to the drafting team regarding overly burdensome costs that need to be considered when addressing the proposed Reliability Standards.	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	

Comment	
There is no technical justification of the reliability-related benefits and costs for this project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The white paper released in December 2020 expressed the importance of ensuring energy adequacy with energy constrained resources. The problem statement identified that unassured fuel supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, can result in insufficient amounts of energy on the system to serve electrical demand and ensure the reliable operation of the Bulk Power System (BPS) throughout the year. Based on the importance of the above listed problem statement, BAL-007 ensures that BAs assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon. Based on the importance of this risk, the DT feels the requirements are at an adequate level to achieve the reliability benefits in a cost-effective manner. In addition, please see technical justification in the SAR. Lastly, this is why questions are asked to industry with regards to the cost implication with regards to the requirements being drafted. This is the time for industry to provide feedback to the drafting team regarding overly burdensome costs that need to be considered when addressing the proposed Reliability Standards.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	No
Document Name	
Comment	
No cost-benefit explanation or analysis was provided.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The white paper released in December 2020 expressed the importance of ensuring energy adequacy with energy constrained resources. The problem statement identified that unassured fuel supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, can result in insufficient amounts of energy on the system to serve electrical demand and ensure the reliable operation of the Bulk Power System (BPS) throughout the year. Based on the importance of the above listed problem statement, BAL-007 ensures that BAs assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon. Based on the importance of this risk, the DT feels the requirements are at an adequate level to achieve the benefits in a cost-effective manner. In addition, please see technical justification in the SAR. Lastly, this is why questions are asked to industry with regards to the cost implication with regards to the requirements being drafted. This is the time for industry to provide feedback to the drafting team regarding overly burdensome costs that need to be considered when addressing the proposed Reliability Standards.	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	No
Document Name	
Comment	
Many utilities, including those within LDWP's Balancing Authority Area, fulfill planning requirements set by their state or local regulatory authorities, making this Standard potentially redundant. From LDWP's perspective, this Standard does not improve reliability and only adds an additional compliance burden to entities.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The white paper released in December 2020 expressed the importance of ensuring energy adequacy with energy constrained resources. The problem statement identified that unassured fuel supplies, including the timing and inconsistent output from variable renewable energy resources, fuel location, and volatility in forecasted load, can result in insufficient amounts of energy on the system to serve electrical demand and ensure the reliable operation of the bulk power system (BPS) throughout the year. Based on the importance of the above listed problem statement, BAL-007 ensures that BAs assess, report, and plan to address forecasted	

Energy Emergencies in the near-term time horizon. Based on the importance of this project, the DT feels the requirements are at an adequate level to not add a cost-effective concern. In addition, please see technical justification in the SAR.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments on BAL-007-1's cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The response if provided on behalf of Exelon representing Segments 1 and 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 the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, 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	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
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	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF

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	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
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	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez

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 will not submit comments on the cost effectiveness of the proposed BAL-007-1 Reliability Standard.

Likes 0	
Dislikes 0	
Response	
Thank you.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

BAL-007-1 Near-term ERAs

4. Provide any BAL-007-1 additional comments for the SDT to consider, if desired.

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

In the Near-Term Energy Reliability Assessment definition, it is unclear which operating day the definition is referring to, and it is unclear whether the term "assessment period" refers to the time period being assessed or the time the responsible entity spends performing the assessment. To clarify this, ERCOT recommends that the definition be revised to read as follows: "An Energy Reliability Assessment that assesses a time period that is between five days and six weeks long and begins no later than two days after the operating day in which the responsible entity begins conducting the Near-Term Energy Reliability Assessment."

In BAL-007-1, Requirement R1, Part 1.2, it is likewise unclear whether "duration" refers to the time period being assessed or the time the responsible entity spends performing the assessment. To clarify this, ERCOT recommends that Part 1.2 be revised to read "The Near-Term ERA process shall specify the length of the time period that the Balancing Authority's Near-Term ERAs will assess."

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT feels that the current proposed definition is clear, based on comments received over the past couple of comment periods, and majority of industry is in agreement with what was proposed in draft 3. The DT does not feel that the proposed language provides additional clarity.

Regarding duration, it is up to the entity to select the duration that works for it based on the parameters placed in the definition of up to 5 days and 6 weeks.

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company supports the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	
Document Name	
Comment	
LDWP also have the following additional comments: 1. Because many utilities already have a comprehensive forward-looking plan that mirrors the Near-Term ERAs, creating a standard will cause undue burden upon the utilities without adding any margin to reliability. This undue burden would come in the form of additional documentation creation, documentation retention, and resources to effectively comply to the new Near-Term ERA requirements throughout the year and during audits (internal and external). 2. Clarification on Reporting Intent: Once a report is submitted to the RC, the Standard does not clearly specify any further actions beyond raising awareness. Is the primary intent of the Standard solely to inform the RC, or are additional measures anticipated? 3. Defining Forecasted Energy Constraints: Energy Emergency Alerts (EEAs) pertain to real-time events, whereas this Standard addresses forecasted energy or capacity shortfalls. LDWP suggests establishing a separate term, such as "Energy or Capacity Constrained Events" (ECCE), to distinguish forecasted constraints from real-time emergencies.	

4. Is sub-requirement 2.1.2 essential? Entities are already mandated by BAL-002 to maintain Operating Reserves, which entities should already plan for through the Energy Planning Assessment period. Duplication of reserve requirements may be unnecessary.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1. The DT respectfully disagrees that BAL-007-1 will cause an undue burden. Please see the Energy Assurance White Paper, which explains the importances of why this standard is needed today. Link to white paper: https://www.nerc.com/comm/RSTC/ERATF/ERATF%20Energy%20Adequacy%20White%20Paper.pdf 2. In previous drafts, it was proposed that the BA and RC complete back and forth coordination. Industry clearly explained that they felt this was an administrative burden based on the back and forth requirements drafted. At this point in the process, the DT feels it is important that the RC is made aware of the assessments completed. The RC may respond and if back and forth is completed by both functional entities, that additional step would be encouraged in the process. 3. Forecasted EEAs are different from current EEAs. 4. Sub-Part 2.1.2. is important because modeling the effects of energy supply contingencies is critical to preparedness. While they may not require explicit actions to be taken in the absence of the occurrence of a contingency, neglecting the possibility of energy supply contingencies in an Energy Reliability Assessment will leave BAs unprepared when unexpected outages do occur. More simply put, ignoring the possibility of contingencies exposes operators to risks that they may not be prepared to mitigate.	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	

Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
It is the continued opinion of ACES that by referencing the EEA levels defined in EOP-011 Atachment 1 Section B, the SDT is deviating from the long-established precedent of NERC Reliability Standards being "stand-alone". While we appreciate the difficulties faced by the SDT in meeting the deadline established for the proposed BAL-007-1, we do not agree that referencing another standard is the correct approach. We **strongly** recommend the SDT include the applicable EEA levels in an attachment to BAL-007-1 and not reference another Reliability Standard. Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Per the NERC Standards process, it is fine to point to the EEAs in EOP-011 from BAL-007. Any drafting team making changes in the future, are required to review all connections that may change the intent from what is being modified and address accordingly.	
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	
We would like to thank the Drafting Team for considering the previous comments and understanding the impacts of how this new reliability standard may disproportionately affect organizations based on their business practices, corporate structure, and membership in cooperative organizations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Please see ACES comments, AEPC has signed on to ACES comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to ACES.	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
Answer	
Document Name	
Comment	

For Requirement 1.3.1, “Each BA will conduct Near Term ERAs for all time periods…” are we to assume all time periods means the daily time period AND the monthly time period?

For Requirement 1.1.4, do the “Known Bulk Electric System Transmission constraints that limit the ability of generation to deliver their output to load” have to be identified in the Near-Term Energy Reliability Assessment period?

In Requirements 3 & 5, the operating plan for Energy Emergencies (EEA2 and EEA3) are documented in the EOP-011 Operating Plan. Is there a reason to have it here also?

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Requirement R1 Part 1.3.1. This is for all time periods.

Requirement R1 Part 1.1.4. Yes, it has to be identified in the Near-Term Energy Reliability Assessment period. Please see parent requirement.

Requirements R3 and R5. It is important that EEAs remain in BAL-007-1. There are three EEA levels, two of which are associated with forecasted Energy Emergencies. The criteria for forecasted Energy Emergency apply also to Scenarios identified in Requirement 2. This level of granularity allows for the BA to design an Operating Plan that fits the specific situation. Some Scenarios may be expected to enter the lower levels of an Energy Emergency, and the actions in an Operating Plan should be appropriate for that combination. Finally, by leveraging the existing terms used in EOP-011 for EEA, clear and well-understood definitions are already in place which require little to no training, beyond the advanced timing associated with BAL-007-1. BAs have existing interpretations of how they respond when nearing or entering an EEA and the existing interpretations are expected to be used, including those that involve interaction with Reserve Sharing Groups.

The DT does not believe that the EEAs descriptions need to be in this standard in addition to EOP-011 so that the two standards remain aligned. Per the NERC Standards process, it is fine to point to the EEAs in EOP-011 from BAL-007. Any drafting team making changes in the future, are required to review all connections that may change the intent from what is being modified and address accordingly.

Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	
Document Name	
Comment	
Ameren supports the comments provided by MISO: **Purpose**: Should "time horizon" be "Operations Planning horizon?" To assess, report, and plan to address forecasted Energy Emergencies in the near-term *time horizon*. **Part 2.1.4.** Eliminate the word "best" as illustrated below. **2.1.4.** Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the best information available at the time of Scenario development.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The focus of BAL-007-1 is Near-Term ERAs for operations planning. The team feels the current purpose within the standard is clear and has been accepted by majority of industry. Please see the updated BAL-007-1 where "best" has been removed from Requirement R2 Part 2.1.4.	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	

Minnesota Power supports MRO's NERC Standards Review Forum's (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	
Document Name	
Comment	
It is difficult to contemplate how NERC will measure compliance with this standard. What if conditions change such that different actions are necessary than what is filed/planned in the ERA? Are there ramifications or compliance issues?	
Likes 0	
Dislikes 0	
Response	
The standard lays out the what is an ERA and timeframe of an ERA, where needed, and not the how to perform an ERA. It is up to the entity to draft its processes and follow the process it has laid out for its entities regarding the ERA. If conditions change, then you will update your process accordingly.	
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 project.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	
Document Name	
Comment	
In the definition of Near-Term Energy Reliability Assessment, the term “no later than two days after the operating day” could be clarified to align better with the definition of Operational Planning Analysis. Clearer language should be used such as “current day” instead of “operating day”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT feels that the current proposed definition is clear, based on comments received over the past couple of comment periods, and the majority of industry is in agreement with what was proposed in draft 3. The DT does not feel that the proposed language provides additional clarity.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	

Coordinate "Effective Date" reference in the Standards (TOP-003 and BAL-007) to be consistent—either call out the Project (probably correct way) or the Standard—may be a Quality Review item. For Evidence Retention, six months is an ineffective retention date to demonstrate Requirement R6 evidence. The Evidence Retention needs to extend there to 24 calendar months as a minimum to be auditable in an effective manner. Without evidence being retained there would be a lot of questions needing answered to ascertain efforts. Requirement R2 VSL discussing the method for Scenario creation but the language of R2 does not support the VSL (see comment above regarding R2). Requirement R6 VSL uses the descriptor "ERA" in front of Scenarios but that is not in the language of the Standard. In the Implementation Plan, "Assessment" needs to be lower-cased in the proposed definition for Energy Reliability Assessment (second to last word in definition). The Implementation Plan for the definitions does not coincide with implementation of TOP-003-7 which uses "Near-Term Energy Reliability Assessment". The DT should match the 18 month Implementation Plan of TOP-003-7 to be effective for the definitions.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the updated Implementation Plan regarding the "Effective Date." In addition, the evidence retention section in TOP-003-7 has been updated with the Near-Term Energy Reliability Assessments for Requirements R2 and R4. Please see the updated Requirements R2 and R6 VSLs. Lastly, "Assessments" has been lowercased in the Implementation Plan.	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	
Document Name	

Comment	
APS offers the following comments for consideration: • Currently, the BAL-007-1 Draft 3 "Purpose" states: *To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.* The purpose statement as written appears to indicate that Balancing Authorities are to assess Energy Emergencies, report Energy Emergencies and address Energy Emergencies which is not the intent of the proposed Standard. Rather, the intent is for Balancing Authorities to assess their specific risks to mitigate potential Energy Emergencies and mitigate. To provide greater specificity, the Standard Drafting Team should consider the following proposed revisions to the BAL-007-1 purpose statement as such: *To ensure the Balancing Authority has documented its Near-Term Energy Reliability Assessment process for identifying its risks, establishing plans to address risks, implement actions where applicable and report to its Reliability Coordinator(s).* • The BAL-007-1 Draft 3 version proposes to remove the Reliability Coordinator from the Standards Applicability and solely identifies the Balancing Authority. In the BAL-007-1 Draft 3 version, Requirement 6 requires the BA to provide its Near-Term ERA process, scenarios, and Operating Plans to the RC, however, it is unclear what the expectation is for the Reliability Coordinator upon receipt of the information. The Standard Drafting Team should consider incorporating and/or marrying the expectations in Reliability Coordinator related Standards, such as IRO-010-4. • The Balancing Authority and overall grid reliability are essential functions of electricity providers. In order to achieve and maintain this high level of reliability, providers already perform near term assessments of load and resource balances, reserve margins and fuel availability on a continuous basis. When potential problems are identified, mitigating actions are taken. Adding additional administrative burdens to document common industry practices is unnecessary and wasteful, potentially tying up resources that would be more effective elsewhere. This proposed standard would only add administrative burdens and costs to entities without adding incremental reliability benefits.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The focus of BAL-007-1 is Near-Term ERAs for operations planning. The team feels the current purpose within the standard is clear and has been accepted by majority of industry.	

In previous drafts, it was proposed that the BA and RC complete back and forth coordination. Industry clearly explained that they felt this was an administrative burden based on the back and forth requirements drafted. At this point in the process, the DT feels it is important that the RC is made aware of the assessments completed. The RC may respond and if back and forth is completed by both functional entities, that additional step would be encouraged in the process. The DT respectfully disagrees that BAL-007-1 will cause an undue burden. Please see the Energy Assurance White Paper, which explains the importances of why this standard is needed today. Link to white paper: https://www.nerc.com/comm/RSTC/ERATF/ERATF%20Energy%20Adequacy%20White%20Paper.pdf

Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	

Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF.	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	
Document Name	
Comment	
Purpose: Should "time horizon" be "Operations Planning horizon?" To assess, report, and plan to address forecasted Energy Emergencies in the near-term *time horizon*. **Part 2.1.4.** Eliminate the word "best" as illustrated below. **2.1.4.** Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The focus of BAL-007-1 is Near-Term ERAs for operations planning. The team feels the current purpose within the standard is clear and has been accepted by majority of industry. Please see the updated Requirements R2 and the removal of the word "best."	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	

Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
Suggest modifying: Purpose: “To assess, report, and plan to address forecasted Energy Emergencies in the **Operations Planning** time horizon”. 2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based upon the information available at the time of Scenario development.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The focus of BAL-007-1 is Near-Term ERAs for operations planning. The team feels the current purpose within the standard is clear and has been accepted by majority of industry.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	
Document Name	

Comment	
Purpose: Should "time horizon" be "Operations Planning horizon?" *To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.* **Part 2.1.4.** Eliminate the word "best" as illustrated below. **2.1.4.** Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The focus of BAL-007-1 is Near-Term ERAs for operations planning. The team feels the current purpose within the standard is clear and has been accepted by majority of industry. Please see the updated Requirement R2 and the removal of the word "best."	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	
Document Name	
Comment	
Purpose: Should "time horizon" be "Operations Planning horizon?" To assess, report, and plan to address forecasted Energy Emergencies in the near-term *time horizon*. **Part 2.1.4.** Eliminate the word "best" as illustrated below. **2.1.4.** Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The focus of BAL-007-1 is Near-Term ERAs for operations planning. The team feels the current purpose within the standard is clear and has been accepted by majority of industry. Please see the updated Requirement R2 and the removal of the word "best."	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
BC Hydro appreciates the drafting team's efforts and the opportunity to comment, and offers the following comments and suggestions: 1. Requirement R2 Part 2.1 as written appears to only apply if the BA elected to document a set of Scenarios. If the intent is for Part 2.1 to also apply if a methodology is chosen instead, BC Hydro recommends that R2 be revised to clarify whether the expectations to have a base Scenario and stressed Scenarios due to 2.1.1 through 2.1.4 conditions would also need to be part of the methodology. 2. Requirement R2 Part 2.1.4 includes the word "best". Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the best information available at the time of Scenario development. BC Hydro recommends that the word "best" be removed as "best" is not measurable or auditable. 3. Measure M2 as written ("Each Balancing Authority shall document the rationale for the Scenarios") appears to set a new Requirement, i.e. document a rationale, in addition to R2, which only requires documentation of Scenarios (or method). BC Hydro requests that the Measure M2 be revised to conform to the language of the Requirement R2. 4. Requirement R3 requires a BA to document one or more Operating Plan(s) (OP(s)) to implement in response to forecasted Energy Emergencies, Requirement R5 requires a BA to implement the OP(s) as documented in Requirement R3 and Requirement R6 requires a BA to review the OP(s) at least every 24 calendar months. These three together can be interpreted that the intent of Requirement R3 is	

for a BA to have a standing OP(s) that can be implemented for any forecasted Energy Emergency as opposed to specific OP(s) created once an individual Energy Emergency has been forecasted. This interpretation would also align with EOP-011-4 which requires a standing OP that is then implemented when an Energy Emergency happens. The technical rationale also implies a standing OP(s) as the wording mentions prior to forecasting Energy Emergencies. However, as Requirement R3 is not specific, another interpretation for Requirement R3 is that specific OP(s) are documented for each forecasted Energy Emergency after an Energy Emergency has been forecasted. This alternate interpretation would not align with Requirement R6 as there would be no standing OP(s) to review.

BC Hydro recommends that the drafting team clarify if the intent of Requirement R3 is for the BA to have a standing OP(s) which then, under Requirement R5 would be implemented for any forecasted Energy Emergency where specifics would be captured and which would align with Requirement R6; or if the intent is that the BA have a specific OP(s) for a forecasted Energy Emergency developed after an Energy Emergency is forecasted in which case Requirement R6 would need to be revised to remove the review of the OP(s) as the OP(s) would constantly be developed when a new Energy Emergency is forecasted.

If Requirement R3 is intended that OP(s) be created for specific forecasted Energy Emergencies, then if a BA has never had a forecasted Energy Emergency, they would not have an OP(s) under Requirement R3.

Regardless of which interpretation is chosen, as Requirement R3 does not specify a timeline for the BA to notify its RC of the OP(s), it's possible the OP(s) could have the RC notification be anytime (ex. notify RC of the forecasted Energy Emergency and OP(s) six months after the forecasted Energy Emergency). BC Hydro recommends revising Requirement R3 to include a timeline to notify the RC of the documented OP(s).

5. Requirement R6 references a BA's "applicable Reliability Coordinator", which can be subject to interpretation.

BC Hydro recommends that "applicable" be changed to "its" Reliability Coordinator which would align with the other Requirements as well as EOP-011.

6. BC Hydro notes that Requirement R6 includes providing the Near-term ERA process, Scenarios or methods to the applicable Reliability Coordinator. Therefore, the Reliability Coordinator would not see the Near-term ERA process, Scenarios or methods until potentially two years after they are documented. BC Hydro recommends documenting the reliability benefit of providing the Near-term ERA process, Scenarios or methods to the Reliability Coordinator as, as drafted, it is not timely and seems to be for information only.

7. Measure M6 requires each BA to "have evidence that it reviewed and documented its Near-term ERA process, Scenarios or methods, and Operating Plan(s) to its Reliability Coordinator". BC Hydro suggests that M6 requires a grammar check. Similarly, the VSL Table for R6 Severe VSL would require a grammar check.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. 1. The set of scenarios created from the process governed by the *method for developing Scenarios* should include the conditions in 2.1.1, 2.1.2, 2.1.3, and 2.1.4. 2. "best" has been removed from the Requirement R2 language. 3. Measure R2 has been updated to align with Requirement R2. 4. Operating Plans should be completed by Requirement R3. 5. The DT does not feel that "applicable" would be confusing when speaking to the applicable RC for the respective BA. 6. There is nothing precluding a BA from providing information to the RC earlier than two years. 7. The Requirement R6 measure has been updated to reflect the Requirement R6 language.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	

Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	
Document Name	
Comment	
Portland General Electric has two concerns with BAL-007 as currently drafted: First, the Requirements in the current draft for BAL-007 appear to document the Standard assessments that are occurring throughout the industry today. It is unclear whether any new actions will need to be taken, other than additional documentation of what is already being done. This only serves the purposes of compliance audits and reduces the value the Standard sought to add in the first place. Second, the SAR discusses the need for assessment of major regional or interconnection-wide disruptions, such as the loss of a major gas pipeline. This type of disruption could impact many Balancing Authorities and Reliability Coordinator areas simultaneously. In this situational example, each Balancing Authority potentially impacted by the outage would only be aware of the local impact, not the potential net regional impact. Each Balancing Authority would not know what responses other entities were taking because of the	

disruption. It is reasonable to expect that each Balancing Authority would assume that their own gas plant capacity (or variable energy resources if that is what is being assessed) could be replaced by going to the market, based on historical availability, without the total impact being covered as part of any one assessment. As stated in comments on the previous draft, the Balancing Authority is not an appropriate entity to rely on, or put the burden on, for interconnection-wide reliability assessments. Per the NERC webinar on 10/10/24, there would be value if BA's, RC's and other regional entities came together to perform such assessments, but that is not a Requirement of BAL-007. Today, some regional entities are already pursuing this type of assessment, and others are not. There is no reason to believe that BAL-007 will change this. For that reason, BAL-007 does not appear to address the primary concerns from the SAR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The purpose of BAL-007-1 is to assess the risks associated with Energy Emergencies in the near-term time horizon and take appropriate actions to address identified risk. As the Bulk-Power System becomes more reliant upon energy-constrained and variable resources, traditional capacity-based planning methods and strategies might not identify energy-related risks to reliable System operation. It is important for entities to assess and be prepared for the next week operations. The DT updated BAL-007-1 based on industry comments received in the course of this project. The draft you see before you today, is where industry is in agreement. While additional assessments should be performed to assess system wide risks, this does not preclude the reliability benefit derived from BAs performing Near-term ERAs.	

TOP-003-7

5. The drafting team (DT) modified TOP-003-6 to ensure industry that Near-Term ERA type data can be requested. Do you agree with the proposed changes? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Donald Lock - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The information in TOP-003-7 R1.3.1, R1.3.2, R2.3.1 and R2.3.2 matches exactly that which must be developed by GOs for EOP-012-2, suggesting that generation plants are to forward this material to TOPs and BAs, who are then to make use of it. That exchange is not mandated by TOP-003-7, however, which says that TOPs and BAs shall have, “Provisions for notification of BES generating unit(s)…,” i.e. TOP/BA-to-GO. Did you mean to call for GO-to-TOP/BA notification. i.e. from, not of?	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Thank you for your comments. TOP-003-7 Requirement R1 has been updated to reflect the correct language from TOP-003-6. Changes made are to make it clear that Near-Term ERA are to be part of the process. There are no specific changes on how you notify. That is up to the entities.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	

Comment	
The Requirement R1 of the proposed TOP-003-7 (Draft 1) requires the TOP to maintain documented specification for the data and information necessary for it to perform its Energy Reliability Assessments. The currently adopted TOP-003-6.1 Requirement R1 does not reference Energy Reliability Assessments. This drafted change has not been identified in the red line version of the proposed TOP-003-7, it was not covered during the October 10, 2024 industry webinar, nor was this proposed change indicated in any other documentation. BC Hydro recommends that the language of R1 be revised to remove Energy Reliability Assessments which would align with TOP-003-6.1 R1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. TOP-003-7 Requirement R1 has been updated to reflect the correct language from TOP-003-6.	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA appreciates the effort made by the DT to make changes based on industry feedback. BPA has identified a few areas for improvement in this draft. Please see comments below. BPA identified that R1 (applicable to the TOP) includes language pertaining to 'Energy Reliability Assessments'. The ERA language was included in TOP-003-7 but not redlined as new from previous versions of TOP-003. BPA recommends the drafting team remove this language as Energy Reliability Assessments will be applicable to the BA, as per BAL-007-1, and included under R2 and R4 of TOP-003-7.	

BPA seeks clarity regarding the DT's inclusion of 'Near-Term' pertaining to ERA in TOP-003-7 R2 and R4. BPA has concerns that including a specific assessment term in the requirement language could potentially require standard revisions if any future assessments (or new terms/definitions) that may require data per TOP-003 are created. BPA offers a potential language revision for R2 and R4:

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions ***(e.g., Energy Reliability Assessments, etc.)*** and Real-time monitoring. The data specification shall include, but not be limited to:

R2.1. A list of data and information needed by the Balancing Authority to support its analysis functions ***(e.g., Energy Reliability Assessments, etc.)*** and Real-time monitoring including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions ***(e.g., Energy Reliability Assessments, etc.)*** and Real-time monitoring.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. TOP-003-7 Requirement R1 has been updated to reflect the correct language from TOP-003-6.

Based on industry feedback, half of industry was concerned that they would not be able to request data needed from TOP-003 to address Near-Term Energy Reliability Assessment in BAL-007-1. The DT added Near-Term ERA to TOP-003 to make it clear that this type of data can be requested via TOP-003. Per the standards development process, any time a definition is updated or changed, the DT making the change is to review all location. TOP-003 would be in that review before any modifications made and of course would go through the comment and ballot period with industry for comment and approval. Based on the last round of comments, majority of industry requested ERA be updated to the specific Near-Term ERA in TOP-003 as that is the data needed to address BAL-007-1. Therefore, the DT feels that Near-Term ERA is the appropriate term to use in TOP-003-7.

Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez

Answer	No
Document Name	
Comment	
R1 and R2 seem duplicative and ripe for error if you have shared responsibilities for the same information with the TO and BA. The applicability to the TO is also confusing as BAL-007 is specific to the BA. It is also unclear how compliance is evaluated - is NERC or the TO/BA identifying the relevant entities that have data and information required by the TO and/or BA's Operational Planning Analyses, Real-time monitoring, and Energy Reliability Assessments?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. TOP-003-7 Requirement R1 has been updated to reflect the correct language from TOP-003-6.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments on TOP-003-6’s proposed updates.	
Likes 0	
Dislikes 0	
Response	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	

Comment	
Duke Energy supports the changes made to TOP-003-6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
There is an accidental reference to Energy Reliability Assessments in TOP-003-7 in R1, even though the BAL-007 data is not applicable to TOPs. As mentioned in the NERC project 2022-03 Energy Assurance Industry Webinar on 10/10/2024, this reference will be removed on the next draft.	
Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Thank you for your comment. TOP-003-7 Requirement R1 has been updated to reflect the correct language from TOP-003-6.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	
Comment	

EEI supports the changes made to TOP-003-6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes
Document Name	
Comment	
TOP-003-7 R1 is only applicable to the TOP functions. It's not indicated as a redline but "Energy Reliability Assessments" were added to the R1 main requirement. This should be removed as it looks like it was added by mistake when the Near-Term Energy Assessments were added to the BA Requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. TOP-003-7 Requirement R1 has been updated to reflect the correct language from TOP-003-6	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) on question 5	

Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	Yes
Document Name	
Comment	
APS agrees with the proposed changes to TOP-003-7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	Yes
Document Name	
Comment	
ITC agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	

Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
WEC Energy Group supports the changes made to TOP-003-6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	

"See EEI Comments"	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to TOP-003-6.	
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 and BANC	
Answer	Yes
Document Name	
Comment	
The proposed changes are minimal and will cause no undue burden on Balancing Authorities.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The response if provided on behalf of Exelon representing Segments 1 and 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 the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	

Bryan Bennett - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
SDG&E needs to see what additional data, if any, will be needed by the CAISO as our BA so that they can perform the new Near-Term Energy Reliability Assessment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 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	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF	
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	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
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	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed that TOP-003-7 Requirement R1 includes Energy Reliability Assessments in the documented specifications that the TOP shall maintain. BAL-007-1 requires BAs to conduct and Energy Reliability Assessment, but there does not appear to be a parallel requirement in TOP-003-7 for TOPs. Is it the intent of the SDT to require TOPs also conduct a Energy Reliability Assessment? Subpart 1.1 does not mention Energy Reliability Assessments. Texas RE is also concerned that the TOPs do not have the necessary system-wide level information for conducting Energy Reliability Assessments and would potentially be duplicating the work of the BAs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. TOP-003-7 Requirement R1 has been updated to reflect the correct language from TOP-003-6.	

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
Should TOP-003-7 take into account the scenario where a Near-Term ERA is determined to be not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s) as per BAL-007-1 R1.3.1? R1 of TOP-003-6.1 does not request maintaining documented specifications for data and information necessary for it to perform Energy Reliability Assessments, yet it has been added to R1 and is not redlined. Was it meant to be added to this requirement in this standard or was it meant for BAL-007-1? If meant for TOP-003-7, should Energy Reliability Assessments be listed in R1.1 as well given it is a sub requirement of R1?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. TOP-003-7 Requirement R1 has been updated to reflect the correct language from TOP-003-6.	

TOP-003-7

6. The DT drafted the TOP-003-7 implementation plan allowing 18 months to become compliant. Do you agree with the updated implementation plan? If you do not agree, please provide your recommendation, and if appropriate, technical, or procedural justification suggestions for revisions.

Bryan Bennett - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Unknown at this time. SDG&E needs to see what additional data, if any will be needed by the CAISO before we are able to determine if 18 months will be sufficient time to become compliant.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.	
Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
Answer	No
Document Name	
Comment	

IID believes that the implementation plan for TOP-003-7 should be the same 24-months implementation schedule as BAL-007-1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT made TOP-003-7 effective at 18-months to allow GOs/GOPs to prepare data to be requested by BAs at the 24-month effective timeframe. The DT still feels that 18 months is appropriate for TOP-003-7 and 24 for BAL-007-1.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support the proposed Implementation Plan for TOP-003-7 because it was not appropriately aligned with the Near-Term Energy Reliability Assessment definition Implantation Plan. EEI notes that this term will not go into effect until 6 months after TOP-003-7. Given this term is used in both Requirements R2 and R4 the implementation plan should not be approved until the implementation plan for this term is harmonized with the proposed implementation plan for TOP-003-7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	

"See EEI Comments"	
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 supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	No
Document Name	
Comment	
Ameren supports the comments provided by MISO:	

There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that do not become effective until 24 months following FERC approval. MISO proposes the Standard Drafting Team align the two so that they become effective at the same time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
More information is needed to clarify TO and BA responsibilities, the documentation and evidence for required data and information and compliance obligations, in general.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Stephanie Kenny - Edison International - Southern California Edison Company - 6	
Answer	No
Document Name	
Comment	

See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Allie Gavin - Allie Gavin On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Allie Gavin	
Answer	No
Document Name	
Comment	
ITC agrees with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	
APS agree with the following EEI comments: EEI does not support the proposed Implementation Plan for TOP-003-7 because it was not appropriately aligned with the Near-Term Energy Reliability Assessment definition Implantation Plan. EEI notes that this term will not go into effect until 6 months after TOP-003-	

7. Given this term is used in both Requirements R2 and R4 the implementation plan should not be approved until the implementation plan for this term is harmonized with the proposed implementation plan for TOP-003-7.	
Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7. Please see the DT's response to EEI.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation would like to see the Implementation Period changed to 24 months to align with the effective date of the definition for the Near-Term Energy Reliability Assessment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT made TOP-003-7 effective at 18-months to allow GOs/GOPs to prepare data to be requested by BAs at the 24-month effective timeframe. The DT still feels that 18 months is appropriate for TOP-003-7 and 24 for BAL-007-1.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that don't become effective until 24 months following FERC approval. NV Energy would recommend that the terms that are currently defined in BAL-007 have an implementation date prior to TOP-003-7 becoming effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 6	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to MRO NSRF and EEI.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No

Document Name	
Comment	
Dominion Energy supports EEI comments on the necessity to coordinate this standard's effective date with the effective date of the new definition in BAL-007.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	No
Document Name	
Comment	
There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that don't become effective until 24 months following FERC approval. ISO.RTO Council Standards Review Committee (IRC SRC) proposes the Standard Drafting Team align the two so that they become effective at the same time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months to line up with the 18-month implementation of TOP-003-7.	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	No

Document Name	
Comment	
PNM does not support an 18 month implementation timeline for TOP-003-7 due to the Near-Term Reliability Assessment definition will not go into effect until 24 months after FERC approval. PNM would support a 24 month implementation of TOP-003-7. PNM also supports EEI's comments regarding question 6.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT made TOP-003-7 effective at 18-months to allow GOs/GOPs to prepare data to be requested by BAs at the 24-month effective timeframe. The DT still feels that 18 months is appropriate for TOP-003-7 and 24 for BAL-007-1.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	No
Document Name	
Comment	
Tri-State Generation and Transmission agrees with the MRO NSF Submitted Comments.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to MRO NSRF	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	

TOP-003 goes into effect in 18 months versus BAL-007's 24 months, but uses the new glossary term from BAL-007 "Near-Term Energy Reliability Assessment." This means that TOP-003 would be effective using a NERC glossary term that **is not effective** yet.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
The implementation plan for TOP-003-7 is 18 months following FERC approval. The implementation plan for BAL-007 is 14 months following FERC approval. TOP-003-7 refers to definitions in BAL-007. It is recommended that the definitions in BAL-007 are implemented prior to implantation of TOP-003-7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months to line up with the 18-month implementation of TOP-003-7.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that don't become effective until 24 months following FERC approval.

MRO NSRF would recommend that the terms that are currently defined in BAL-007 have an implementation date prior to TOP-003-7 becoming effective.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

There is a mismatch in the implementation plan criteria. While standard TOP-003-7 becomes effective in 18 months following FERC approval, it refers to definitions under BAL-007 that don't become effective until 24 months following FERC approval.

MRO NSRF would recommend that the terms that are currently defined in BAL-007 have an implementation date prior to TOP-003-7 becoming effective.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.

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

Answer	No
Document Name	
Comment	
Duke Energy does not support the proposed TOP-003-7 Implementation Plan but does support the following EEI response: EEI does not support the proposed Implementation Plan for TOP-003-7 because it was not appropriately aligned with the Near-Term Energy Reliability Assessment Definition Implantation Plan. EEI notes that this term will not go into effect until 6 months after TOP-003-7. Given this term is used in both Requirements R2 and R4 the implementation plan should not be approved until the implementation plan for this term is harmonized with the proposed implementation plan for TOP-003-7.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
The Implementation Plan for TOP-003-7 is not aligned with the Near-Term Energy Reliability Assessment Definition Implantation Plan. This term will not go into effect until 6 months after TOP-003-7. Given this term is used in both Requirements R2 and R4 the implementation plan should not be approved until the implementation plan for this term is in parallel with the proposed implementation plan for TOP-003-7. FirstEnergy asks the DT to clarify.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.	
Constantin Chitescu - Ontario Power Generation 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 submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	

Comment	
Exelon does not oppose 18 months to implement TOP-003. Exelon supports the concerns stated in the EEI comments regarding the opportunity to improve alignment between the implementation of the two standards. The response if provided on behalf of Exelon representing Segments 1 and 3	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.	
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	
The proposed implementation timelines are sufficient for entities to both identify any additional data needed, and to communicate to entities the additional data request.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Fausto Serratos - Los Angeles Department of Water and Power - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
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	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,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	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
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	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, 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	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	
There is a mismatch in the implementation dates for TOP-003-7 and definitions in BAL-007 that come into effect at a later date than the TOP-003-7 standard.	

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT updated the implementation plan to reflect that the definition will be effective 18-months following FERC approval to line up with the 18-month implementation of TOP-003-7.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro is unable to support the implementation plan at this time as additional clarifications to Requirements are needed prior to assessing the implementation plan.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

TOP-003-7

7. The DT proposes that the modified TOP-003-7 meets the Standards Authorization Request 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.

Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	No
Document Name	
Comment	
There is no technical justification of the reliability-related benefits and costs for this project.	
Likes 0	
Dislikes 0	
Response	
Please see the white paper explaining the importance of this project. https://www.nerc.com/comm/RSTC/ERATF/ERATF%20Energy%20Adequacy%20White%20Paper.pdf	
Bryan Bennett - Sempra - San Diego Gas and Electric - 3	
Answer	No
Document Name	
Comment	
Unknown at this time. SDG&E needs to see what additional data, if any will be needed by the CAISO before we are able to determine what the costs will be to provide the data.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Matthew Jaramilla, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no comments on TOP-003-7's cost effectiveness	
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	
Yes, there should be minimal impact on entities who must provide additional data to the Balancing Authorities under these proposed revisions to the Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The response if provided on behalf of Exelon representing Segments 1 and 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 the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	
Please see the DT's response to EEI.	
Brooke Jockin - Portland General Electric Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Julie Hall - Entergy - 6, Group Name Entergy	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Anna Lavik - Puget Sound Energy, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lock - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tamarra Hardie - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Duane Franke - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Perry - PNM Resources - 1,3 - WECC,Texas RE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Heather Pierce - Puget Sound Energy, Inc. - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Helen Lainis - Independent Electricity System Operator - 2, Group Name IRC SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF	
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	
Greg Sorenson - Greg Sorenson On Behalf of: Tremayne Brown, ReliabilityFirst , 10; - Greg Sorenson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Danielle Moskop - Danielle Moskop On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Danielle Moskop	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Vicky Budreau - Santee Cooper - 3, Group Name Santee Cooper	
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	
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	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Fausto Serratos - Los Angeles Department of Water and Power - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Denise Sanchez - Denise Sanchez On Behalf of: Diana Torres, Imperial Irrigation District, 1, 6, 5, 3; George Kirschner, Imperial Irrigation District, 1, 6, 5, 3; Jesus Sammy Alcaraz, Imperial Irrigation District, 1, 6, 5, 3; Tino Zaragoza, Imperial Irrigation District, 1, 6, 5, 3; - Denise Sanchez	
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 will not submit comments on the cost effectiveness of the proposed TOP-003-7 Reliability Standard.	

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	

8. Provide any TOP-003-7 additional comments for the SDT to consider, if desired.

Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	
Document Name	
Comment	
ERCOT notes that TOP-003-7 Requirement R1 includes a reference to Energy Reliability Assessments. This reference appears to be unnecessary, as R1 is limited to Transmission Operator data specifications, and BAL-007-1 is not applicable to Transmission Operators.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see updated standard that removed ERA from R1 of TOP-003-7.	

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company supports the submitted comments by EEI.	
Likes 0	
Dislikes 0	
Response	

Please see the DT's response to EEI.	
Shannon Mickens - Shannon Mickens On Behalf of: Joshua Phillips, Southwest Power Pool, Inc. (RTO), 2; - Shannon Mickens, Group Name SPP RTO	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
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.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	

Document Name	EEI Near Final Draft Comments _ Project 2022-03 BAL-007 & TOP-003 Rev 0c _ 11_01_2024 (1).docx
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to EEI.	
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 project.	
Likes 0	
Dislikes 0	
Response	
Please see the DT’s response to NPCC.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	
Document Name	
Comment	

Please correct the numbering in the subsections of the "C. Compliance section" they should read 1.1 to 1.3 instead of 4.1.1 to 4.1.3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see updated standard.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC Entity Monitoring	
Answer	
Document Name	
Comment	
Evidence Retention sections need to be modified to add references to "Near-Term Energy Reliability Assessments". "Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions**, Real-time monitoring, and Near-Term Energy Reliability Assessments** in accordance with Requirement R2 and Measurement M2 as well as any documents in force since the last compliance audit." "Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis **, Real-time monitoring, and Near-Term Energy Reliability Assessments** in accordance with Requirement R4 and Measurement M4."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the updated Standard.	
Jessica Lopez - APS - Arizona Public Service Co. - 3	
Answer	

Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Mary Smith - Southern Indiana Gas and Electric Co. - 1,3,5,6 - Texas RE,RF	
Answer	
Document Name	
Comment	
N/A	
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	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	
Document Name	
Comment	
The draft TOP-007-1 only includes the Near-Term ERA definition, which relies on the new ERA proposed definition. The proposed implementation plan indicates that the newly proposed definitions become effective "when the proposed standard is approved", which may imply that ERA would only become effective upon approval of BAL-007-1. If BAL-007-1 is not approved on or before TOP-003-7 is approved, the Near-Term ERA definition may not be enforceable. BC Hydro suggests that the Implementation Plan be revised to ensure that the new ERA and Near-Term ERA definitions become effective at the same time.	
Likes 1	JEA, 1, McClung Joseph
Dislikes 0	
Response	
Thank you for your comment. Please see updated implementation plan.	
Andy Thomas - Duke Energy - 1,3,5,6 - SERC,RF	
Answer	
Document Name	
Comment	
None.	

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

End of Report

Reminder

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Ballots and Non-binding Poll Open through November 4, 2024

Now Available

Additional ballots for **BAL-007-1 Near-term Energy Reliability Assessments** and initial ballots for **TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection** and their non-binding polls of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Monday, November 4, 2024**.

Regarding BAL-007-1, the standard drafting team's considerations of the responses received from the last comment period are reflected in this draft of the standard.

Reminder Regarding Corporate RBB Memberships

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

Balloting

Members of the ballot pools associated with this project can log in and submit their votes by accessing the Standards Balloting and Commenting System (SBS) here.

Note for BAL-007-1: Votes cast in previous ballots, will not carry over to additional ballots. It is the responsibility of the registered voter in the ballot pools to place votes again. To ensure a quorum is reached, if you do not want to vote affirmative or negative, cast an abstention.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*

- *Please be mindful of ballot and comment period closing dates. We ask to* ***allow at least 48 hours*** *for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts* ***prior to the last day*** *of a comment/ballot period.*

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will review all responses received during the comment period and determine the next steps of the project.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources 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

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Formal Comment Period Open through November 4, 2024
Ballot Pools for TOP-003-7 Forming through October 18, 2024

Now Available

A 47-day formal comment period for **draft three of BAL-007-1 Near-term Energy Reliability Assessments** and **draft one of TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection** is open through **8 p.m. Eastern, Monday, November 4, 2024.**

Regarding BAL-007-1, the standard drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

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 **for TOP-003-7** are being formed through **8 p.m. Eastern, Friday, October 18, 2024.** Registered Ballot Body members can join the ballot pools here.

- *Contact NERC IT support directly at https://support.nerc.net/ (Monday – Friday, 8 a.m. - 5 p.m. Eastern) for problems regarding accessing the SBS due to a forgotten password, incorrect credential error messages, or system lock-out.*
- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*

- *Please be mindful of ballot and comment period closing dates. We ask to* ***allow at least 48 hours*** *for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts* ***prior to the last day*** *of a comment/ballot period.*

Next Steps

An additional ballot for BAL-007-1 and initial ballot for TOP-003-7 and their implementation plans, as well as the non-binding polls of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 25 – November 4, 2024**.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2022-03 Energy Assurance with Energy-Constrained Resources 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/351)
Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 TOP-003-7 IN 1 ST
Voting Start Date: 10/25/2024 12:01:00 AM
Voting End Date: 11/4/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 222
Total Ballot Pool: 260
Quorum: 85.38
Quorum Established Date: 11/4/2024 4:26:12 PM
Weighted Segment Value: 92.77

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	73	1	48	0.923	4	0.077	0	15	6
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	64	1	44	0.917	4	0.083	0	6	10
Segment: 4	15	1	10	1	0	0	0	1	4
Segment: 5	57	1	30	0.857	5	0.143	0	8	14
Segment: 6	38	1	25	0.862	4	0.138	0	5	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.3	3	0.3	0	0	0	2	0
Totals:	260	6.1	168	5.659	17	0.441	0	37	38

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		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	Avista - Avista Corporation	Mike Magruder		None	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	Travis Grablander		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 Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	None	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Lower Colorado River Authority	Matt Lewis		Abstain	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		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle 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. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
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	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Wolverine Power Supply Cooperative, Inc.	Andrew Anderson		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	CPS Energy	Juan Gomez		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		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
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		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	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	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	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seattle City Light	Zenon O'young-Chu		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	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	Wabash Valley Power Association	Scott Berry		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		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Abstain	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seattle City Light	Robert Jones		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Affirmative	N/A
4	Western Power Pool	Kevin Conway		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	Arevon Energy	Srinivas Kappagantula		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		None	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Abstain	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		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		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	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	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		None	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seattle City Light	Daren Brubaker		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

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Showing 1 to 260 of 260 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/351)
Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 Implementation Plan IN 1 OT
Voting Start Date: 10/25/2024 12:01:00 AM
Voting End Date: 11/4/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 218
Total Ballot Pool: 254
Quorum: 85.83
Quorum Established Date: 11/4/2024 4:29:18 PM
Weighted Segment Value: 76.3

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	72	1	37	0.712	15	0.288	0	15	5
Segment: 2	7	0.7	7	0.7	0	0	0	0	0
Segment: 3	62	1	33	0.702	14	0.298	0	6	9
Segment: 4	14	0.9	7	0.7	2	0.2	0	1	4
Segment: 5	57	1	24	0.686	11	0.314	0	8	14
Segment: 6	37	1	19	0.679	9	0.321	0	5	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	254	6	131	4.578	51	1.422	0	36	36

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	Comments Submitted
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		None	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		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Negative	Comments Submitted
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	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		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Affirmative	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. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Wolverine Power Supply Cooperative, Inc.	Andrew Anderson		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	CPS Energy	Juan Gomez		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted
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	Imperial Irrigation District	George Kirschner	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		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	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	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	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	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	Wabash Valley Power Association	Scott Berry		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	Georgia System Operations Corporation	Katrina Lyons		Abstain	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		None	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	Comments Submitted
4	Western Power Pool	Kevin Conway		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		Negative	Comments Submitted
5	Arevon Energy	Srinivas Kappagantula		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Negative	Comments Submitted
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		None	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Abstain	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		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		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		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	Talen Generation, LLC	Donald Lock		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Invenergy LLC	Colin Chilcoat		None	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		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		None	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources | Non-binding Poll TOP-003-7 | Non-binding Poll IN 1 NB
Voting Start Date: 10/25/2024 12:01:00 AM
Voting End Date: 11/4/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 205
Total Ballot Pool: 243
Quorum: 84.36
Quorum Established Date: 11/4/2024 4:44:23 PM
Weighted Segment Value: 86.09

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	69	1	35	0.833	7	0.167	20	7
Segment: 2	7	0.4	4	0.4	0	0	3	0
Segment: 3	59	1	33	0.846	6	0.154	10	10
Segment: 4	14	0.9	9	0.9	0	0	1	4
Segment: 5	56	1	25	0.833	5	0.167	11	15
Segment: 6	33	1	21	0.875	3	0.125	7	2
Segment: 7	0	0	0	0	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: 10	5	0.3	3	0.3	0	0	2	0
Totals:	243	5.6	130	4.988	21	0.612	54	38

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	Ameren - Ameren Services	Tamara Evey		Abstain	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Affirmative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		None	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		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		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 Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	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	Affirmative	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	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		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Abstain	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
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. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	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	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Wolverine Power Supply Cooperative, Inc.	Andrew Anderson		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	CPS Energy	Juan Gomez		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		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
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Negative	Comments Submitted
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Abstain	N/A
3	Northern California Power Agency	Michael Whitney		None	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	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	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	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	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	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	Wabash Valley Power Association	Scott Berry		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	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Abstain	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Utility Services, Inc.	Carver Powers		None	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Affirmative	N/A
4	Western Power Pool	Kevin Conway		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.	Andrew Smith		Affirmative	N/A
5	Arevon Energy	Srinivas Kappagantula		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		None	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	Affirmative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	Comments Submitted
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NextEra Energy	Richard Vendetti		None	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Abstain	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Abstain	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		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		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	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	Talen Generation, LLC	Donald Lock		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Abstain	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/351)
Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 AB 3 ST
Voting Start Date: 10/25/2024 12:01:00 AM
Voting End Date: 11/4/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 233
Total Ballot Pool: 265
Quorum: 87.92
Quorum Established Date: 11/4/2024 3:52:13 PM
Weighted Segment Value: 81.53

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	49	0.845	9	0.155	0	14	3
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	58	1	39	0.848	7	0.152	0	5	7
Segment: 4	9	0.7	5	0.5	2	0.2	0	0	2
Segment: 5	63	1	33	0.805	8	0.195	0	9	13
Segment: 6	44	1	27	0.794	7	0.206	0	4	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	0	1
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.5	4	0.4	1	0.1	0	2	0
Totals:	265	6	164	4.892	35	1.108	0	34	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		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		None	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
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	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	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Los Angeles Department of Water and Power	faranak sarbaz		Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	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		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	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		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		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	Broc Bruton	Abstain	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	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Third-Party Comments
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		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
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	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	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Negative	Comments Submitted
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Abstain	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	Comments Submitted
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	N/A
3	Tennessee Valley Authority	Ian Grant		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	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Third-Party Comments
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	Calpine Corporation	Whitney Wallace		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	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	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Third-Party Comments
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	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	Talen Generation, LLC	Donald Lock		Negative	Comments Submitted
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Third-Party Comments
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Abstain	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 265 of 265 entries

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/351)
Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources Implementation Plan AB 3 OT
Voting Start Date: 10/25/2024 12:01:00 AM
Voting End Date: 11/4/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 227
Total Ballot Pool: 257
Quorum: 88.33
Quorum Established Date: 11/4/2024 3:48:24 PM
Weighted Segment Value: 83.72

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 1	75	1	48	0.828	10	0.172	0	14	3
Segment: 2	8	0.7	6	0.6	1	0.1	0	0	1
Segment: 3	54	1	36	0.783	10	0.217	0	4	4
Segment: 4	9	0.7	7	0.7	0	0	0	0	2
Segment: 5	59	1	30	0.789	8	0.211	0	8	13
Segment: 6	44	1	28	0.824	6	0.176	0	4	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	0	1
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	257	6	160	5.023	36	0.977	0	31	30

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		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		None	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		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		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 Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Affirmative	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	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Negative	Comments Submitted
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	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		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	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		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		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	Broc Bruton	Abstain	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	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Negative	Comments Submitted
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Affirmative	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		Negative	Comments Submitted
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	Fausto Serratos		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		None	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	N/A
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	Calpine Corporation	Whitney Wallace		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		Negative	Comments Submitted
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	Orlando Utilities Commission	Dania Colon		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Negative	Comments Submitted
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak		Negative	Third-Party Comments
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Negative	Comments Submitted
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		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	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Negative	Comments Submitted
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

Showing 1 to 257 of 257 entries

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BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 | Non-binding Poll AB 3 NB
Voting Start Date: 10/25/2024 12:01:00 AM
Voting End Date: 11/4/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 211
Total Ballot Pool: 246
Quorum: 85.77
Quorum Established Date: 11/4/2024 4:15:14 PM
Weighted Segment Value: 79.61

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	72	1	36	0.8	9	0.2	22	5
Segment: 2	7	0.4	3	0.3	1	0.1	3	0
Segment: 3	53	1	29	0.806	7	0.194	11	6
Segment: 4	9	0.6	4	0.4	2	0.2	0	3
Segment: 5	56	1	23	0.793	6	0.207	13	14
Segment: 6	41	1	22	0.815	5	0.185	8	6
Segment: 7	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1
Segment: 9	0	0	0	0	0	0	0	0
Segment: 10	7	0.5	4	0.4	1	0.1	2	0
Totals:	246	5.5	121	4.313	31	1.187	59	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.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Abstain	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		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	Comments Submitted
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Travis Grablander		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 Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		None	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	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	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	New York Power Authority	Daniel Valle		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Abstain	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	Broc Bruton	Abstain	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	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		None	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	Comments Submitted
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	Comments Submitted
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Abstain	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	Independent Electricity System Operator	Helen Lainis		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		Abstain	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	Comments Submitted
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	None	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		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
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Negative	Comments Submitted
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	Fausto Serratos		Negative	Comments Submitted
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Abstain	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	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	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		None	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	WEC Energy Group, Inc.	Christine Kane		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	Comments Submitted
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	Calpine Corporation	Whitney Wallace		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	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	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		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		Affirmative	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		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	Comments Submitted
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	Comments Submitted
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	Comments Submitted
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Abstain	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Abstain	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		None	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	Comments Submitted
6	Salt River Project	Timothy Singh	Israel Perez	Negative	Comments Submitted
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	Comments Submitted
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Negative	Comments Submitted
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Standard Development Timeline

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

Description of Current Draft

The TOP-003-7 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	September 19 – November 4, 2024

Anticipated Actions	Date
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 10, 2024

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

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

Term(s):

The term Near-Term Energy Reliability Assessment refers to the proposed definition being developed under the Project 2022-03 Energy Assurance. As of this posting, the proposed definition of Near-Term Energy Reliability Assessment is:

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection
2. **Number:** TOP-003-7
3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.
4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider
5. **Effective Date:** See Implementation Plan for Project 2022-03.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following.

1.5.1. Specified deadlines or periodicity which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Provisions to update or correct data and information, as applicable or necessary;

1.5.4. A mutually agreeable format;

1.5.5. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following.

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Provisions to update or correct data and information, as applicable or necessary.

2.5.4. A mutually agreeable format.

2.5.5. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

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

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

Each responsible 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 shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.

- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator,

Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

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

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

<table>
<tr><th rowspan="2">R#</th><th colspan="4">Violation Severity Levels</th></tr>
<tr><th>Lower VSL</th><th>Moderate VSL</th><th>High VSL</th><th>Severe VSL</th></tr>
<tr><td colspan="5">For the Requirement R3 and R4 VSLs only, the intent of the Standard Drafting Team (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.</td></tr>
<tr><td>R3</td><td>The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td><td>The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td><td>The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td><td>The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator’s Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.</td></tr>
<tr><td>R4</td><td>The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority’s analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.</td><td>The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority’s analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.</td><td>The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority’s analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.</td><td>The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority’s analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.</td></tr>
<tr><td>R5</td><td>The responsible entity receiving a specification(s) in Requirement R3 or R4</td><td>The responsible entity receiving a specification(s) in Requirement R3 or R4</td><td>The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations</td><td>The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations</td></tr>
</table>

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	satisfied the obligations in the specification but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	satisfied the obligations in the specification but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	in the specification but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

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		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP- 003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No.RD23-6-000,	

6.1	November 3, 2023	Effective Date	July 1, 2025
7	TBD	Energy Assurance Modifications – Addition of Near-Term ERA.	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

The TOP-003-7 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	September 19 – November 4, 2024

Anticipated Actions	Date
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 10, 2024

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

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

Term(s):

The term Near-Term Energy Reliability Assessment refers to the proposed definition being developed under the Project 2022-03 Energy Assurance. As of this posting, the proposed definition of Near-Term Energy Reliability Assessment is:

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Transmission Operator and Balancing Authority Data and Information Specification and Collection
2. **Number:** TOP-003-7
3. **Purpose:** To ensure that each Transmission Operator and Balancing Authority has the data and information it needs to plan, monitor, and assess the operation of its Transmission Operator Area or Balancing Authority Area.
4. **Applicability:**

   4.1 Functional Entities:

   4.1.1 Transmission Operator

   4.1.2 Balancing Authority

   4.1.3 Generator Owner

   4.1.4 Generator Operator

   4.1.5 Transmission Owner

   4.1.6 Distribution Provider
5. **Effective Date:** See Implementation Plan for Project 2022-03.

B. Requirements and Measures

R1. Each Transmission Operator shall maintain documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments~~, and Energy Reliability Assessments~~. The specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

1.1. A list of data and information needed by the Transmission Operator to support its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments including non-BES data and information, external network data and information, and identification of the entities responsible for responding to the specification as deemed necessary by the Transmission Operator.

1.2. Provisions for notification of current Protection System and Remedial Action Scheme (RAS) status or degradation that impacts System reliability.

1.3. Provisions for notification of BES generating unit(s) during local forecasted cold weather to include:

1.3.1. Operating limitations based on:

1.3.1.1. capability and availability;

1.3.1.2. fuel supply and inventory concerns;

1.3.1.3. fuel switching capabilities; and

1.3.1.4. environmental constraints

1.3.2. Generating unit(s) minimum:

1.3.2.1. design temperature; or

1.3.2.2. historical operating temperature; or

1.3.2.3. current cold weather performance temperature determined by an engineering analysis.

1.4. Identification of a mutually agreeable process for resolving conflicts.

1.5. Method(s) for the entity identified in Part 1.1 to provide the data and information that includes, at a minimum, the following.

1.5.1. Specified deadlines or periodicity which data and information is to be provided;

1.5.2. Performance criteria for the availability and accuracy of data and information as applicable;

1.5.3. Provisions to update or correct data and information, as applicable or necessary;

1.5.4. A mutually agreeable format;

1.5.5. Mutually agreeable method(s) for securely transferring data and information.

M1. Each Transmission Operator shall make available its dated, current, in force documented specification(s) for data and information.

R2. Each Balancing Authority shall maintain documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. The data specification shall include, but not be limited to: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1. A list of data and information needed by the Balancing Authority to support its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments, including non-Bulk Electric System data and information, and external network data and information, as deemed necessary by the Balancing Authority, and identification of the entity responsible for responding to the specification.

2.2. Provisions for notification of current Protection System and Remedial Action Scheme status or degradation that impacts System reliability.

2.3. Provisions for notification of BES generating unit(s) status during local forecasted cold weather to include:

2.3.1. Operating limitations based on:

2.3.1.1. capability and availability;

2.3.1.2. fuel supply and inventory concerns;

2.3.1.3. fuel switching capabilities; and

2.3.1.4. environmental constraints.

2.3.2. Generating unit(s) minimum:

2.3.2.1. design temperature; or

2.3.2.2. historical operating temperature; or

2.3.2.3. current cold weather performance temperature determined by an engineering analysis.

2.4. Identification of a mutually agreeable process in resolving conflicts

2.5. Methods for the entity identified in Part 2.1 to provide data and information that includes at a minimum the following.

2.5.1. Specific deadlines or periodicity in which data and information is to be provided;

2.5.2. Performance criteria for the availability and accuracy of data and information, as applicable;

2.5.3. Provisions to update or correct data and information, as applicable or necessary.

2.5.4. A mutually agreeable format.

2.5.5. A mutually agreeable method(s) for securely transferring data and information.

M2. Each Balancing Authority shall make available its dated, current, in force documented specification(s) for data and information.

R3. Each Transmission Operator shall distribute its data and information specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M3. Each Transmission Operator shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.

Such evidence could include but is not limited to web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, date and contents, or e-mail records.

R4. Each Balancing Authority shall distribute its data and information specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall make available evidence that it has distributed its data specification(s) to entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. Such evidence could include, but is not limited to, web postings with an electronic notice of the posting, dated operator logs, voice recordings, postal receipts showing the recipient, or e-mail records.

R5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a data and information specification(s) in Requirement R3 or R4 shall satisfy the obligations of the documented specifications. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning, Same-Day Operations, Real-time Operations]*

M5. Each Transmission Operator, Balancing Authority, Generator Owner, Generator Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall make available evidence that it has satisfied the obligations of the documented specification. Such evidence could include, but is not limited to, electronic or hard copies of data transmittals or attestations of receiving entities.

C. Compliance

1. Compliance Monitoring Process

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

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

Each responsible 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 shall retain its dated, current, in force, documented specification for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R1 and Measurement M1 as well as any documents in force since the last compliance audit.

- Each Balancing Authority shall retain its dated, current, in force, documented specification(s) for the data and information necessary for it to perform its analysis functions~~ and~~, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R2 and Measurement M2, as well as any documents in force since the last compliance audit.

- Each Transmission Operator shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments in accordance with Requirement R3 and Measurement M3.

- Each Balancing Authority shall retain evidence for three calendar years that it has distributed its specification(s) to entities that have data required by the Balancing Authority's analysis functions~~ and~~, Real-time monitoring, and Near-Term Energy Reliability Assessments in accordance with Requirement R4 and Measurement M4.

- Each Balancing Authority, Generator Owner, Generator Operator,

Transmission Operator, Transmission Owner, and Distribution Provider receiving a specification(s) in Requirement R3 or R4 shall retain evidence for the most recent 90-calendar days that it has satisfied the obligations of the documented specifications in accordance with Requirement R5 and Measurement M5.

1.3. Compliance Monitoring and Enforcement Program: ~~As defined in the NERC Rules of Procedure,~~ "Compliance Monitoring Enforcement Program" or "CMEP" means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program~~" refers~~ (Appendix 4C to the ~~identification~~NERC Rules of Procedure) or the Commission-approved program of ~~the processes~~a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that ~~will be used to evaluate data or information~~is responsible for ~~the purpose of assessing performance or outcomes~~performing compliance monitoring and enforcement activities with ~~the associated reliability standard~~respect to Registered Entities' compliance with Reliability Standards.

Violation Severity Levels

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	The Transmission Operator did not include one or two of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include three of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include four of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not include any of the parts (Part 1.1 through Part 1.5) of the documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments. OR, The Transmission Operator did not have a documented specification(s) for the data and information necessary for it to perform its Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R2	The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not have a documented specification(s) for the data and information necessary for it to perform its analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
For the Requirement R3 and R4 VSLs only, the intent of the Standard Drafting Team (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	The Transmission Operator did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the reliability entities, whichever is greater, that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.	The Transmission Operator did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Transmission Operator's Operational Planning Analyses, Real-time monitoring, and Real-time Assessments.
R4	The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to three entities, or more than 10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.
R5	The responsible entity receiving a specification(s) in Requirement R3 or R4	The responsible entity receiving a specification(s) in Requirement R3 or R4	The responsible entity receiving a specification(s) in Requirement R3 or R4 satisfied the obligations	The responsible entity receiving a specification(s) in Requirement R3 or R4 did not satisfy the obligations

R#	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	satisfied the obligations in the specification but failed to meet one of the parts in Requirement R1 Part1.5 or Requirement R2 Part 2.5.	satisfied the obligations in the specification but failed to meet two of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	in the specification but failed to meet three or more of the parts in Requirement R1 Part 1.5 or Requirement R2 Part 2.5.	of the documented specifications.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

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		Modified R1.2 Modified M1 Replaced Levels of Non-compliance with the Feb 28, BOT approved Violation Severity Levels (VSLs)	Revised
1	October 17, 2008	Adopted by NERC Board of Trustees	
1	March 17, 2011	Order issued by FERC approving TOP- 003-1 (approval effective 5/23/11)	
2	May 6, 2012	Revised under Project 2007-03	Revised
2	May 9, 2012	Adopted by Board of Trustees	Revised
3	April 2014	Changes pursuant to Project 2014-03	Revised
3	November 13, 2014	Adopted by Board of Trustees	Revisions under Project 2014-03
3	November 19, 2015	FERC approved TOP-003-3. Docket No. RM15-16-000, Order No. 817	
4	February 6, 2020	Adopted by NERC Board of Trustees	Revisions under Project 2017-07
4	October 30, 2020	FERC approved TOP-003-4. Docket No. RD20-4-000	
5	May 2021	Changes pursuant to Project 2019-06	Revised
5	June 11, 2021	Board approved	Project 2019-06 Cold Weather
5	August 24, 2021	FERC approved TOP –003-5 Docket No. RD21-5-000, Order 176	
6	TBD	Adopted by NERC Board of Trustees	Revisions under project 2021-06
6.1	Errata	Approved by the Standards Committee	August 23, 2023
6.1	November 2, 2023	FERC Approved TOP-003-6.1 Docket No.RD23-6-000,	

6.1	November 3, 2023	Effective Date	July 1, 2025
7	TBD	Energy Assurance Modifications – Addition of Near-Term ERA.	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

The BAL-007-1 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024
45-day formal comment period with additional ballot	May 7 – June 20, 2024
45-day formal or informal comment period with additional ballot	September 19 – November 4, 2024

Anticipated Actions	Date
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 10, 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Near-term Energy Reliability Assessments
2. **Number:** BAL-007-1
3. **Purpose:** To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
5. **Effective Date:** See Implementation Plan for BAL-007-1.

B. Requirements and Measures

R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a process for conducting Near-Term Energy Reliability Assessments (ERA). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The Near-Term ERA process shall account for:

1.1.1. Forecasted or assumed Demand profiles;

1.1.2. Resource capabilities and operational limitations, including fuel supply;

1.1.3. Energy transfers with other Balancing Authorities; and

1.1.4. Known Bulk Electric System (BES) Transmission constraints that limit the ability of generation to deliver their output to Load.

1.2. The Near-Term ERA process shall specify the duration of the Balancing Authority's Near-Term ERAs.

1.3. The Near-Term ERA process shall specify the frequency at which the Balancing Authority will conduct Near-Term ERAs, subject to the following:

1.3.1. Each Balancing Authority will conduct Near-Term ERAs for all time periods unless the Balancing Authority demonstrates, via a documented methodology, that a Near-Term ERA is not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s).

1.3.2. The documented methodology for identifying time periods for which the Balancing Authority will not conduct a Near-Term ERA must (i) define the criteria used to determine when there is a low risk of an Energy Emergency occurring, and (ii) account for the items listed in 1.1.1 – 1.1.4 and other conditions associated with Energy Emergencies.

M1. Each Balancing Authority shall have evidence that it documented a process for conducting Near-Term ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a set of Scenarios, or a method for developing Scenarios, for use in performing Near-Term ERAs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. The set of Scenarios must include (i) a base Scenario with expected system conditions, and (ii) other Scenarios that stress the system due to the following conditions, as applicable to the Balancing Authority's system:

2.1.1. Higher than forecasted or assumed Demand profiles;

2.1.2. The effects of an energy supply contingency;

2.1.3. The effects of a fuel supply contingency; and

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.

M2. Each Balancing Authority shall have evidence that it documented the Scenarios, or the method of developing Scenarios, for use in performing Near-Term ERAs.

R3. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document one or more Operating Plan(s) to implement in response to forecasted Energy Emergencies, including provisions for notification to their Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it documented its Operating Plan(s) in accordance with Requirement R3.

R4. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, perform Near-Term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall have evidence that it performed the Near-Term ERAs in accordance with Requirement R4.

R5. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, implement its Operating Plan(s), as documented in Requirement R3, when Near-Term ERAs identify any of the following forecasted Energy Emergencies: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B; or
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B.

M5. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) in accordance with Requirement R5.

R6. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, review, update, as necessary, and provide to the applicable Reliability Coordinator its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3, at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have evidence that it reviewed and provided its Near-term ERA process, Scenarios or methods, and Operating Plan(s) to its Reliability Coordinator, in accordance with Requirement R6.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Balancing Authority shall keep data or evidence to show compliance with applicable requirements for six months for Near-Term ERAs or since the last audit.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 or Part 1.2.	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 through Part 1.2. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for one of the elements in Requirement R1 Part 1.3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.
R2.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include one of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include two of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include three of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include any of the conditions listed in Requirement R2 Part 2.1. OR The Balancing Authority failed to document a set of Scenarios or a method of developing

				Scenarios for use in performing Near-Term ERAs.
R3.	N/A	N/A	The Balancing Authority documented an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs.
R4.	N/A	N/A	N/A	The Balancing Authority failed to perform a Near-Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.
R5.	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a Near-Term ERA identified any of the forecasted conditions in Requirement R5.
R6.	N/A	N/A	The Balancing Authority reviewed information that contained the Near-Term ERAs process, the Scenarios or methods, and Operating	The Balancing Authority failed to review, update, and provide the Near-Term ERAs process, the Scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.

			Plan(s) but failed to update within 24 months.	

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan
- NERC Project 2022-03 Technical Rationale
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
1	TBD	NERC Project 2022-03 energy assurance new standard.	New

Standard Development Timeline

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

Description of Current Draft

The BAL-007-1 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024
45-day formal comment period with additional ballot	May 7 – June 20, 2024
45-day formal or informal comment period with additional ballot	September 19 – November 4, 2024

Anticipated Actions	Date
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 10, 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Near-term Energy Reliability Assessments
2. **Number:** BAL-007-1
3. **Purpose:** To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.
4. **Applicability:**
   - **4.1. Functional Entities:**
     - **4.1.1.** Balancing Authority
5. **Effective Date:** See Implementation Plan for BAL-007-1.

B. Requirements and Measures

R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a process for conducting Near-Term Energy Reliability Assessments (ERA). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The Near-Term ERA process shall account for:

1.1.1. Forecasted or assumed Demand profiles;

1.1.2. Resource capabilities and operational limitations, including fuel supply;

1.1.3. Energy transfers with other Balancing Authorities; and

1.1.4. Known Bulk Electric System (BES) Transmission constraints that limit the ability of generation to deliver their output to Load.

1.2. The Near-Term ERA process shall specify the duration of the Balancing Authority's Near-Term ERAs.

1.3. The Near-Term ERA process shall specify the frequency at which the Balancing Authority will conduct Near-Term ERAs, subject to the following:

1.3.1. Each Balancing Authority will conduct Near-Term ERAs for all time periods unless the Balancing Authority demonstrates, via a documented methodology, that a Near-Term ERA is not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s).

1.3.2. The documented methodology for identifying time periods for which the Balancing Authority will not conduct a Near-Term ERA must (i) define the criteria used to determine when there is a low risk of an Energy Emergency occurring, and (ii) account for the items listed in 1.1.1 – 1.1.4 and other conditions associated with Energy Emergencies.

M1. Each Balancing Authority shall have evidence that it documented a process for conducting Near-Term ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a set of Scenarios, or a method for developing Scenarios, for use in performing Near-Term ERAs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. The set of Scenarios must include (i) a base Scenario with expected system conditions, and (ii) other Scenarios that stress the system due to the following conditions, as applicable to the Balancing Authority's system:

2.1.1. Higher than forecasted or assumed Demand profiles;

2.1.2. The effects of an energy supply contingency;

2.1.3. The effects of a fuel supply contingency; and

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the ~~best~~ information available at the time of Scenario development.

M2. Each Balancing Authority shall ~~document the rationale for~~have evidence that it documented the Scenarios, or the method of developing Scenarios, for use in performing Near-Term ERAs.

R3. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document one or more Operating Plan(s) to implement in response to forecasted Energy Emergencies, including provisions for notification to their Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it documented its Operating Plan(s) in accordance with Requirement R3.

R4. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, perform Near-Term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall have evidence that it performed the Near-Term ERAs in accordance with Requirement R4.

R5. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, implement its Operating Plan(s), as documented in Requirement R3, when Near-Term ERAs identify any of the following forecasted Energy Emergencies: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B; or
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B.

M5. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) in accordance with Requirement R5.

R6. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, review, update, as necessary, and provide to the applicable Reliability Coordinator its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3, at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have evidence that it reviewed and ~~documented~~provided its Near-term ERA process, Scenarios or methods, and Operating Plan(s) to its Reliability Coordinator, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

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

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

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

- The Balancing Authority shall keep data or evidence to show compliance with applicable requirements for six months for Near-Term ERAs or since the last audit.

1.3. Compliance Monitoring and Enforcement Program: ~~As defined in the NERC Rules of Procedure, ~~“Compliance Monitoring Enforcement Program” or “CMEP” means, depending on the context (1) the NERC Compliance Monitoring and Enforcement Program~~” refers~~ (Appendix 4C to the ~~identification~~NERC Rules of Procedure) or the Commission-approved program of ~~the processes~~a Regional Entity, as applicable, or (2) the program, department or organization within NERC or a Regional Entity that ~~will be used to evaluate data or information~~is responsible for ~~the purpose of assessing performance or outcomes~~performing compliance monitoring and enforcement activities with ~~the associated~~respect to Registered Entities’ compliance with Reliability ~~Standard~~Standards.

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 or Part 1.2.	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 through Part 1.2. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for one of the elements in Requirement R1 Part 1.3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.
R2.	The Balancing Authority documented a set of Scenarios or a method of ~~Scenario creation~~developing Scenarios but did not include one of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of ~~Scenario creation~~developing Scenarios but did not include two of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of ~~Scenario creation~~developing Scenarios but did not include three of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of ~~Scenario creation~~developing Scenarios but did not include any of the conditions listed in Requirement R2 Part 2.1. OR The Balancing Authority failed to document a set of Scenarios or a method of ~~Scenario~~

				~~creation~~developing Scenarios for use in performing Near-Term ERAs.
R3.	N/A	N/A	The Balancing Authority documented an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs.
R4.	N/A	N/A	N/A	The Balancing Authority failed to perform a Near-Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.
R5.	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a Near-Term ERA identified any of the forecasted conditions in Requirement R5.
R6.	N/A	N/A	The Balancing Authority reviewed information that contained the Near-Term ERAs process, the ~~ERA~~ Scenarios or methods, and Operating	The Balancing Authority failed to review ~~and~~, update ~~information that contained~~, and provide the Near-Term ERAs process, the ~~ERA~~ Scenarios or methods, and

			Plan(s) but failed to update within 24 months.	Operating Plan(s) to the Reliability Coordinator.

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan
- NERC Project 2022-03 Technical Rationale
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
1	TBD	NERC Project 2022-03 energy assurance new standard.	New

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Implementation Plan

Project 2022-03 Energy Assurance with Energy-Constrained Resources | Reliability Standards BAL-007-1 and TOP-003-7

Applicable Standards

- BAL-007-1 – Near-term Energy Reliability Assessments
- TOP-003-7 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement

- TOP-003-6.1 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Transmission Operator
- Generator Owner
- Generator Operator
- Transmission Owner
- Distribution Provider

Terms in the NERC Glossary of Terms

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

Proposed New Definitions:

Energy Reliability Assessment:	Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand

	and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.
Near-Term Energy Reliability Assessment**:**	An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

Background

Energy assurance is an increasingly important aspect of a reliable Bulk-Power System (BPS) but has been inconsistently defined and measured without explicit standards. Project 2022-03 Energy Assurance with Energy-Constrained Resources was initiated to address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Reliability Standard BAL-007-1 – Energy Reliability Assessments is focused on the operations planning time horizon.

Effective Dates

BAL-007-1 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard BAL-007-1 shall become effective on the first day of the first calendar quarter that is 24 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 24 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definitions

Where approval by an applicable governmental authority is required, the definitions of Energy Reliability Assessment and Near-term Energy Reliability Assessment 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 definitions, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definitions of Energy Reliability Assessment and Near-term Energy Reliability Assessment shall become effective on the first day of the first calendar quarter that is 18 months after the date the definitions are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-003-7 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard TOP-003-7 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.

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Implementation Plan

Project 2022-03 Energy Assurance with Energy-Constrained Resources | Reliability Standards BAL-007-1 and TOP-003-7

Applicable Standard~~(s)~~

- BAL-007-1 – Near-term Energy Reliability Assessments
- TOP-003-7 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Requested Retirement~~(s)~~

- TOP-003-6.1 – Transmission Operator and Balancing Authority Data and Information Specification and Collection

Prerequisite Standard~~(s)~~

These standard(s) or definitions must be approved before the Applicable Standard becomes effective:

- None

Applicable Entities

- Balancing Authority
- Transmission Operator
- Generator Owner
- Generator Operator
- Transmission Owner
- Distribution Provider

Terms in the NERC Glossary of Terms

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

Proposed New Definition~~(s)~~:

Energy Reliability Assessment:	Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand

	and to provide Operating Reserves for the Bulk Power System throughout the associated ~~A~~assessment period.
Near-Term Energy Reliability Assessment**:**	An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

Background

Energy assurance is an increasingly important aspect of a reliable Bulk-Power System (BPS) but has been inconsistently defined and measured without explicit standards. Project 2022-03 Energy Assurance with Energy-Constrained Resources was initiated to address several energy assurance concerns related to the operations, operations planning, and mid- to long-term planning time horizons. Reliability Standard BAL-007-1 – Energy Reliability Assessments is focused on the operations planning time horizon.

Effective Dates

BAL-007-1 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard BAL-007-1 shall become effective on the first day of the first calendar quarter that is 24 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 24 months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Definitions

Where approval by an applicable governmental authority is required, the definitions of Energy Reliability Assessment and Near-term Energy Reliability Assessment shall become effective on the first day of the first calendar quarter that is ~~24~~18 months after the effective date of the applicable governmental authority's order approving ~~Reliability Standard BAL-007-1~~the definitions, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the ~~standard~~definitions of Energy Reliability Assessment and Near-term Energy Reliability Assessment shall become effective on the first day of the first calendar quarter that is ~~24~~18 months after the date ~~that Reliability Standard BAL-007-1 is~~the definitions are adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

TOP-003-7 Reliability Standard

Where approval by an applicable governmental authority is required, Reliability Standard TOP-003-7 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.

Public

Technical Rationale

Project 2022-03 Energy Assurance with Energy-Constrained Resources Reliability Standard BAL-007-1 | September 2024

BAL-007-1– Near-term Energy Reliability Assessments

Introduction

This document explains the technical rationale and justification for the proposed Reliability Standard BAL-007-1. It provides stakeholders and the Electric Reliability Organization (ERO) Enterprise with an understanding of the technical requirements in the Reliability Standards. This Technical Rationale and Justification for BAL-007-1 is not a Reliability Standard and should not be considered mandatory and enforceable.

Updates to this document include the Project 2022-03 Energy Assurance with Energy-Constrained Resources Drafting Team's (DT's) intent in drafting new requirements.

Overview

Inconsistent output from variable energy resources, coincident with unassured deliverability of fuel supplies and volatility in load, can result in insufficient amounts of energy available from the Bulk Power System (BPS) needed to serve electrical Demand, maintain sufficient Operating Reserve, and ensure the reliable operation of the BPS. As part of ongoing operations planning, many entities have started incorporating some limited studies of energy reliability assessments that produce key metrics; however, there is inconsistency among entities on how the assessments are performed. To achieve the level of consistency needed across the industry, to reliably predict the energy needed to serve the load, energy reliability assessments for the operations time horizon and the minimization of identified risks are mandated and codified in this new standard. Project 2022-03 proposes two new Reliability Standards, BAL-007-1 and the Energy Reliability Assessment (ERA) definition. The purpose of the proposed Reliability Standard BAL-007-1 is to identify and minimize the risks of forecasted Energy Emergencies in the operations planning time horizon by analyzing the expected resource mix availability.

Rationale for BAL-007-1

As the BPS becomes more reliant upon energy constrained and variable resources, traditional capacity-based planning methods and strategies are being stretched and potentially do not identify energy-related risks to reliably operate and maintain the system. BAL-007-1 is being proposed as a step toward reducing these potential risks and to begin the transition to energy-based planning methods and strategies that incorporate critical time-based variables that are not captured in capacity-based processes.

BAL-007-1 is intended to provide Balancing Authorities (BAs) with the tools necessary to successfully navigate a system that has both variable load and resources.

BAL-007-1 Operating Plan(s), which are not intended to replace or supersede TOP-002 and EOP-011 Operating Plans, are intended to provide a list of actions over a longer-term/earlier time period that can reduce the severity of or fully mitigate the need to implement TOP-002 and/or EOP-011 plans.

The new Reliability Standard can be separated into three basic activities:

- Developing and documenting an ERA process, Scenarios or a method for creating them, and Operating Plans (Requirements 1-3).
- Performing ERAs as documented (Requirement 4).
- Comparing to forecasted Energy Emergency conditions and, if identified, implementing Operating Plan(s) in response to energy reliability risks (Requirement 5).

The purpose of the standard is to assess energy risk in the Operations Planning time horizon, determine if the identified risks are acceptable, and take action when appropriate. It should be noted that the standard offers the flexibility to allow for either a deterministic or probabilistic implementation of an ERA process. This has been left up to the BA to determine which method is right for their region. This standard improves reliability through identifying energy risks earlier and being able to implement longer lead time activities to mitigate those risks.

Relationship to Other Standards

While the proposed standard has similarities to other standards, especially TOP-001, TOP-002, and EOP-011, the proposed standard addresses reliability risks due to gaps in the existing reliability standards by focusing on different time horizons than current standards and energy risks which are not clearly addressed. In many cases, the language is intentionally similar to language in those requirements but applicable to different time horizons. The BAL-007-1 standard looks at a near-term time horizon which is longer than other operations planning assessment requirements. In terms of addressing energy risks, BAL-007-1 more clearly outlines the assessment requirements to look at energy over an assessment period rather than capacity assessments generally used to comply with current standards.

TOP-001 and TOP-002 provide requirements for assessments and Operating Plans in real-time and operations planning time horizons, but their requirements are limited to, at most the next day, which limits the options that Balancing Authorities may take to respond. BAL-007-1's proposed language extends this outlook to at least greater than five days and up to six weeks ahead, so BAs have time to implement mitigation actions with longer lead times (e.g., reschedule outages, conserve consumable fuel, source additional fuel) and have better situational awareness of potential reliability risks.

TOP-002, EOP-011, and BAL-007-1 all require Operating Plans to minimize or mitigate reliability risks, but they would likely differ in what actions that a BA would deem appropriate to be included in each. Since BAL-007-1 is assessing a longer time horizon, the projected conditions are more uncertain, and the Operating Plans developed should reflect that. Instead of identifying specific actions that must be taken, the Operating Plans under BAL-007-1 are expected to have more general processes than Operating Plans in TOP-002. BAL-007-1 Operating Plans are not intended to replace TOP-002 and EOP-011 Operating Plans but to identify

additional actions that can be implemented when potential risks are identified with a longer lead time and with an energy component of the assessment. The goal of these longer-term Operating Plans is to reduce the likelihood, or the severity of, an actual Energy Emergency occurring, which would require an EOP-011 Operating Plan. Actions that are taken as outlined in the BAL-007-1 Operating Plans would then lead into the day-ahead Operating Plans and real time, through the establishment of more favorable initial conditions, rather than overlapping them. An example timeline of how BAL-007-1 and EOP-011 would interact is shown below in *Figure 1* when the TOP-002 associated Operating Plans are not sufficient to avoid an Energy Emergency. Ideally, the longer-term Operating Plan(s) would result in the EOP-011 Operating Plan not being needed but if an Energy Emergency still occurs, the Operating Plans should have reduced the severity of the Energy Emergency.

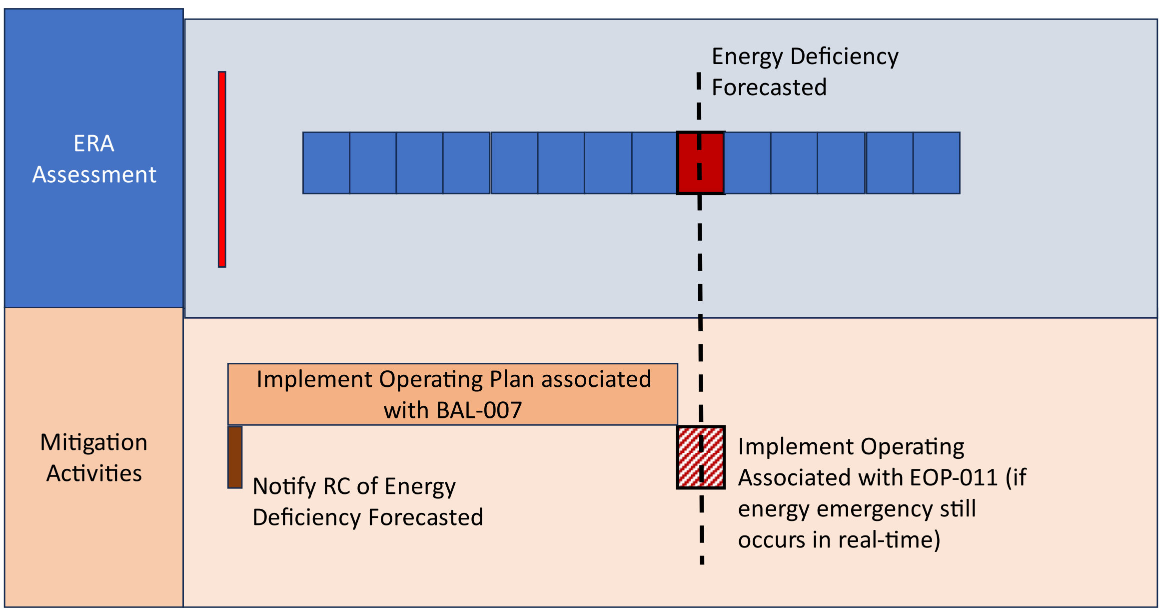

Figure 1. Timeline of ERA performance and Operating Plan Implementation if the forecasted energy deficiency is not fully mitigated when EOP-011 Operating Plan is still required.

Additionally, the BAL-007-1 assessments require considering energy risk which can only be performed by looking at an assessment over a time period with multiple time steps and considering the fuel supply and the production from just-in-time, variable energy resources. While EOP-011 Requirement R2 includes “Energy Emergencies” as a risk that Operating Plans must address, these assessments have generally been performed as capacity assessments, or potentially a series of capacity assessments in succession, which do not necessarily include variable energy and fuel risk, especially over a longer period of time. BAL-007-1 explicitly requires including these elements in an assessment and set criteria regarding when risks need to be addressed through Operating Plans.

The Balancing Authority (BA) may require additional data from other entities and should consider this when documenting the process. While BAL-007-1 does not require other entities to provide necessary data, TOP-003 requires the BA to "maintain a documented specification for the data necessary for it to perform its analysis functions…" in Requirement R2 and requires the other entities to provide the data in Requirement R5. To provide further clarity in TOP-003, "Near-term Energy Reliability Assessments" has been added to the list of activities for which the Balancing Authorities maintain and distribute a data specification for which applicable entities are required to provide.

Proposed New Terms:

Energy Reliability Assessment (ERA) – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

Rationale

The ERA definition was added to allow for Energy Reliability Assessments to be performed in different time horizons using similar processes prescribed by NERC standards, but also through other processes while maintaining a consistent understanding of what an ERA is. These assessments are intended to look at the wide variety of resources available to serve load's energy requirements not only in the near-term but also in other time horizons including the long-term planning horizon. ERAs go beyond the existing scope of the capacity assessments that have traditionally been performed to look more closely at energy needs.

The definition for Near-Term Energy Reliability Assessment provides further details for this specific type of ERA. Within the definition are requirements for the duration of a Near-Term ERA. It is the intent that Near-Term ERAs are performed on a routine basis and look at the time period that covers the next several days to weeks, and that all time periods will be effectively covered by some iteration of a Near-Term ERA. Assessments would be repeated as no later than when one expires to extend the outlook for the BA performing the ERA. To that end, in the interest of maintaining relevancy of the ERA, a five-day to six-week limit is placed on the duration. While six weeks is a long period of time, it gives regions the flexibility to assess the energy landscape over a period of time that encompasses the energy risks that they deem to be pertinent. It is expected that most Balancing Authorities will update their Near-Term ERAs on a more frequent basis, but the baseline requirement is flexible to allow for longer periods. The minimum duration of five days gives the Balancing Authority the foresight to evaluate fuel constraints and weather anomalies. Fuel constraints, specifically natural gas scheduling timelines, typically extend through a single day (e.g., today for tomorrow) during the week, and three-day strips over weekends. Holidays introduce a longer strip than the typical weekends. Five-day strips are traded at least once per year and sometimes more than once depending on where holidays fall on the calendar. That construct is one example of the factors that set the minimum of five days for Near-Term ERAs. Weather dependent resources, where prevalent, would drive the consideration for longer-duration assessments. Doldrums in wind and solar production will have a historical expectation for how long they typically last and should be considered with determining the minimum duration of the Near-Term ERA. Finally, there is a requirement that the initialization data being used to perform a Near-Term ERA be current. This is spelled out as "an assessment period that begins no later than two days after the operating day", the operating day being the day on which the ERA is being performed, or started, or completed. One interpretation that meets this requirement is that the first day of the Near-Term ERA is the current day, which is no later than two days out and provides good initialization of the models being used to perform the assessment. What this is intended to prevent is performing all

Near-Term ERAs in a single assessment at the start of a year or season, maintaining current, relevant, and useful information for the BA to make sound decisions.

Requirements:

Requirement R1

Requirement R1 identifies the basis for defining what a Near-Term ERA is. Basic input assumptions are specifically designed by each BA according to their risks and their supply resource mix and demand profiles. Because of differences in risks and in resource mixes and demand profiles between regions, rather than requiring a set of prescriptive elements to assess, each BA is provided with minimum assessment requirements which they will use to define their scope for performing their ERAs and document a rationale.

Balancing Authorities may perform the required ERAs for just their area or a group of BAs may jointly perform their ERAs. This is consistent with existing partnerships (e.g., Reserve Sharing Groups or resource adequacy collaboratives) between BAs that are used for other operations or planning activities and real time operations, and should be reflected in Near-Term ERAs and their associated Operating Plan(s). Should a deficiency be identified, the BAs, regardless of whether they performed their assessment jointly or individually, are expected to utilize all of their available resources, including those in other BA areas. The goal of the ERA is to determine if sufficient energy is available to meet demand at all times.

Demand profiles will be determined by the BA as well. Entities will have a number of items to consider prior to determining their Demand profile. It is up to the BA to determine exactly how Demand will be modeled, including considerations of how demand response is treated. A BA may choose to include market based or dispatchable demand response, but it is recommended that other forms of demand response should not be included, which would leave load reduction options as a last resort (e.g., voltage reduction, load cycling, etc.). Each BA will need to identify what their type of demand response is and when, if ever, to consider it. Load shed should only be identified as part of a plan if this is the last resort.

The heart of an ERA is the modeling of resource capabilities and their fuel supplies. This modeling includes constrained fuel supplies such as natural gas, inventoried fuels such as oil, coal, liquefied natural gas and some hydro, and just-in-time fuels like wind, solar, and run-of-river hydro. ERAs look at the production from generating resources over a period of time, which will impact their operation. Constrained fuels will deplete, limiting the operation of generation (i.e., fuel). All of these considerations go into modeling resource capabilities and operational limitations, including fuel supply.

Energy transfers with other Balancing Authorities is required to be modeled as well. This modeling is simply the interchange between areas that BAs count on in their day-to-day operation of their systems. It is recommended that BAs coordinate these assumptions to ensure consistencies on the common interface, but may not be required depending on the scope of the ERA as it is defined.

Finally, known Bulk Electric System (BES) Transmission constraints, that limit the ability of generation to deliver their output to load, are required to be included in the Near-Term ERA. This requirement was carefully worded such that a power flow or load flow analysis is NOT required to be performed, however

when a system has a known constraint that causes area generation to always be limited under certain specific conditions, and those conditions are expected to occur, then that generation should be reduced in the ERA as well.

ERAs should ensure that every period of time is evaluated, and document the frequency and duration that meets that intent. For example, performing a two-week long ERA every two weeks would meet the requirement. The determination of how long to study will be based on several factors such as system or generation outage recall timing, accuracy of forecast information beyond the next few days, or lead time for fuel replenishment. Each Balancing Authority will conduct a Near-Term ERA for all time periods unless the BA demonstrates that a Near-Term ERA is not necessary. This can be accomplished via screening tools that evaluate all of the factors above for risk and show that risk is low for that period of time. This requires documentation of the methods used to make that determination as well as the evaluation of the factors considered.

Requirement R2

Requirement R2 outlines a minimum set of Scenarios that must be included in a Near-Term ERA. The intent is to provide a mechanism for each BA to gauge whether or not they are close to an Energy Emergency. Credibility of the Scenarios is for the BA to define and document. The selected Scenarios are intended to stress the system, but may fall short of causing an Energy Emergency on their own. For example, raising demand during light load periods may not result in stressed system conditions, but would meet the intent of stressing the system. The BA is in full control of determining what Scenarios are appropriate.

There are four types of Scenarios, two for supply, one for Demand, and a combination of the two based on historically observed conditions that could occur again. Each of the Scenarios can be varied independently or in combination with each other. At least one parameter should be varied enough to stress the system to determine if the (remaining) available resources are robust enough to meet the Demand and Operating Reserves. A possible Scenario for Demand profiles could be raising Demand from a 50/50 profile to a higher profile, such as a 90/10 or maximum load Scenario, to measure the impact to the system and determine if energy shortfalls are forecasted. There are two supply side Scenarios to be included in the ERA. The first is an energy supply contingency that effectively removes energy resources from the base case and runs it again. Large energy resources may be the same as large capacity resources, but not necessarily in all cases. Typically, the results of the base Scenario will show the analyst what the largest source of energy is, which would be removed from the energy supply contingency Scenario. The second supply Scenario removes a set of resources that are supplied by the same fuel supply. This is traditionally thought of as natural gas supplying multiple generating stations and may be just that, but could also be a set of wind turbines that are closely situated, where a storm or lull could render them unavailable or with a very low production for a period of time. It could also include the loss of energy from solar panels that are covered by snow or smoke from a fire. The final Scenario is more versatile and can be tailored by the BA based on actual events that happened and could happen again within the horizon being assessed. This Scenario should be specific to the region, the time of year, the forecasted conditions, and any other expected conditions that the BA includes in the Near-Term ERA. For example, modeling a snow storm that covers solar panels during the winter months in a location where snow is prevalent makes sense but modeling the same storm during the

summer is unreasonable and is not expected to be done. It is possible that this Scenario is simply documented that there are no historical events that fit the current forecasted conditions, or that the Scenario is the same as those described in R2.1.1 through 2.1.3. When this occurs, the Balancing Authority should include that description in their process.

Regardless of the chosen energy and fuel Scenarios, it is up to the BA to determine which resource or set of resources are included in the ERA. The choices by the BA in Scenarios must be identified and documented.

Requirement R3

The time horizon specified in the Near-Term ERA definition offers a different vantage point than next day and real-time capacity assessments. The actions that a BA can take due to an identified risk of an energy shortfall are different when identified days to weeks earlier than if waiting for a next day or real-time capacity assessment. They are also different when comparing the energy aspect of the ERA to a capacity assessment. An example of actions that could be taken based on the results of a Near-Term ERA that may not be available for a next day or real-time assessment include requesting for energy resources or transmission facilities to return from maintenance or construction outages earlier than planned or to postpone a planned outage. Additional actions that could be considered for an energy shortfall that would be overlooked in a capacity assessment is the conservation of stored fuel or the optimization of energy storage (e.g., pumped storage hydro or batteries). If an entity were to wait for the next day studies to identify a risk, fewer options for the BA to avoid an energy risk in real time would be available.

Provisions for communication with the Reliability Coordinator is simply a documented process including the forecasted conditions when the RC will be alerted to the results of the Near-Term ERA and/or the implementation of Operating Plans. Many of the actions that are included in Operating Plans will not require communication of any kind (e.g., waiting for better forecasts), but some may require that communication (e.g., recall of transmission facilities). The procedure used to document the performance of Near-Term ERAs including a section that clearly defines what communications are required by the BA meets this requirement.

Requirement R3 requires BAs to develop Operating Plans prior to forecasting Energy Emergencies through ERAs to minimize their effects. These Operating Plans are developed so that in the event that an ERA shows that a BA may have insufficient energy, they will have an Operating Plan ready to implement, per Requirement R3, that has been developed and communicated before system conditions are unfavorable and be ready for later implementation. Operating Plans are expected to include actions that can be performed by the BA within the time horizon for which the ERA is designed, near-term. The actions that BAs may include in Operating Plans will also provide information to the BA regarding how long the assessment period of the ERA might need to be (Requirement R1) such that they can have time to accomplish the actions identified. For example, if actions that could minimize potential Energy Emergencies take two weeks to accomplish, the ERA should be looking at least two to three weeks into the future.

As discussed in the Relationship to other Standards section, the Operating Plans developed based on this requirement are not intended to supersede Operating Plans associated with TOP and EOP standards but to

complement them and include actions that could reduce the likelihood or severity of an energy deficiency occurring in real-time. To that end, the BA develops an appropriate Operating Plan for a forecasted Energy Emergency that is identified by an ERA. Depending if the ERA is completed weeks or days prior to the forecasted Energy Emergency, the BA decides on suitable plans to reduce the impact. Since the Operating Plans are being implemented based on assessments looking days to weeks ahead, considering the associated uncertainty of the results, BAs may decide to exclude actions in the BAL-007-1 Operating Plans which would only need to occur much closer to the projected event or only plan to implement those actions if the projected conditions of the ERA appear that they will still occur. For example, an Operating Plan may include increasing the frequency of performing ERAs in order to monitor whether the forecasted Energy Emergency is more or less likely as the uncertainty of input data to the assessment decreases and other actions in the Operating Plan have been implemented. Again, the goal of performing an ERA is to identify those times when a forecasted Energy Emergency might occur. The developed Operating Plan should have steps that can be taken to reduce, or mitigate, the forecasted Energy Emergency.

The ERA Operating Plans should be designed to be adaptable to unfolding conditions and proactive enough to possibly avoid an energy shortage through advanced actions. As an example, to illustrate the Operating Plan uses, when an ERA is performed two weeks ahead of a calculated shortfall then potential actions have a two-week timeline to perform the appropriate action plans as well as monitor if the identified risk conditions have changed. For instance, if the results from a two-week duration ERA during an extremely cold period determines an Energy Emergency may occur, the BA's Operating Plan could include the following actions:

- Survey scheduled outage system to determine if any generation currently out for maintenance can return earlier than planned.
- Survey if any transmission outages affect either generation deliverability or import capability. If yes, can they be returned to service prior to the forecasted Energy Emergency.
- Survey if generation and transmission scheduled to go out can defer their outages until after the event.
- Communication with Reliability Coordinator and other relevant entities of the projected risk (e.g., government authorities for assessing the need and strategy for public appeals for conservation, or other BAs to account for expected imports or exports and potentially facilitate higher transfers).
- Ensure all energy storage units can be fully available to help mitigate energy shortfalls.
- Increase frequency of performance of ERAs, including possibly daily, and assess energy availability and have Operating Plan actions conditional on the level of risk.
- If ERA results still indicate unacceptable risk of energy deficiency two days prior to projected event, instruct thermal plants to warm up leading up to event to avoid outages due to ice formation and cold-start issues.

Ideally, these actions will reduce or prevent an Energy Emergency that might occur in real-time. However, if the Energy Emergency still occurs, these actions should reduce the energy deficiency and prepare the BAs

to implement an emergency Operating Plan. This scenario is intended only to be one simple illustrative example that does not reflect all potential Operating Plan actions or actions that BAs in all regions can do.

While scheduling increased imports can be a part of the Operating Plan, it is imperative that the BA verify that the resources they have scheduled will continue to be there to solve their Energy Emergency. It should not be assumed that once imports are scheduled, this energy is a firm supply. Both BAs may be impacted by the event causing an Energy Emergency for both areas. The supplying entity may not be able to honor their agreement to provide this energy.

Requirement R4

Requirement R4 specifies that the near-term ERA be performed as designed.

Requirement R5

Requirement R5 specifies what constitutes two circumstances that identify a forecasted Energy Emergency. The forecasted Energy Emergency conditions are intended to be a clear threshold where the ERA results identify levels of impending risk and require actions be performed to minimize the potential they will occur. The definitions of what constitutes a forecasted Energy Emergency are in alignment with the Energy Emergency Alert (EEA) definitions in EOP-011. The difference for BAL-007-1 is that instead of being a real-time Energy Emergency, these would be forecasted events. The goal here is that if an Energy Emergency is forecasted in an ERA, the associated Operating Plan will have targeted steps to help minimize the forecasted Energy Emergency before it gets to be an Energy Emergency in the next day and real-time timeframes.

There are three EEA levels, two of which are associated with forecasted Energy Emergencies. The criteria for forecasted Energy Emergency apply also to Scenarios identified in Requirement 2. This level of granularity allows for the BA to design an Operating Plan that fits the specific situation. Some Scenarios may be expected to enter the lower levels of an Energy Emergency, and the actions in an Operating Plan should be appropriate for that combination.

Finally, by leveraging the existing terms used in EOP-011 for EEA, clear and well-understood definitions are already in place which require little to no training, beyond the advanced timing associated with BAL-007-1. BAs have existing interpretations of how they respond when nearing or entering an EEA and the existing interpretations are expected to be used, including those that involve interaction with Reserve Sharing Groups.

Requirement R6

Requirement R6 requires that the BA review their process, Scenarios, and Operating Plans, in Requirements R1 through R3, to determine if any changes are needed. The BA shall review this documentation at least once every 24 months. Due diligence during the design and review phases by the BA is required to identify potential risks and possible actions that could minimize those risks that would lead to an energy shortfall in the near-term timeframe.

Violation Risk Factor and Violation Severity Level Justifications

Project 2022-03 Energy Assurance with Energy-Constrained Resources

This document provides the drafting team's (DT's) justification for assignment of violation risk factors (VRFs) and violation severity levels (VSLs) for each requirement in Project 2022-03 Energy Assurance with Energy-Constrained Resources. 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 DT applied the following NERC criteria and FERC Guidelines when developing the VRFs and VSLs for the requirements.

NERC Criteria for Violation Risk Factors

High Risk Requirement

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

Medium Risk Requirement

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

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

FERC Guidelines for Violation Risk Factors

Guideline (1) – Consistency with the Conclusions of the Final Blackout Report
FERC seeks to ensure that VRFs assigned to Requirements of Reliability Standards in these identified areas appropriately reflect their historical critical impact on the reliability of the Bulk-Power System. In the VSL Order, FERC listed critical areas (from the Final Blackout Report) where violations could severely affect the reliability of the Bulk-Power System:

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

Guideline (2) – Consistency within a Reliability Standard

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

Guideline (3) – Consistency among Reliability Standards

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

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

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

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

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

NERC Criteria for Violation Severity Levels

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

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

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

FERC Order of Violation Severity Levels

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

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

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

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

A violation of a “binary” type requirement must be a “Severe” VSL.
Do not use ambiguous terms such as “minor” and “significant” to describe noncompliant performance.

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

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

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

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

VRF Justifications for BAL-007-1, Requirement R1	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the process for conducting Energy Reliability Assessments for the near-term time horizon which are required in defining the minimum standards by which Energy Reliability Assessments will be performed 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 BAL-007-1, Requirement R1			
Lower	**Moderate**	**High**	**Severe**
N/A	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 or Part 1.2.	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 through Part 1.2. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for one of the elements in Requirement R1 Part 1.3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.

VSL Justifications for BAL-007-1, Requirement R1	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSLs use the same terminology as used in the associated requirement and are, therefore, consistent with the requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	Each VSL is based on a single violation and not cumulative violations.

VRF Justifications for BAL-007-1, Requirement R2	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining a set of scenarios or a method of Scenario creation which are required in defining the minimum standards by which near-term Energy Reliability Assessments will be performed 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 BAL-007-1, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include one of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include two of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include three of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include any of the conditions listed in Requirement R2 Part 2.1. OR The Balancing Authority failed to document a set of Scenarios or a method of developing Scenarios for use in performing Near-Term ERAs.

VSL Justifications for BAL-007-1, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not 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 BAL-007-1, Requirement R3	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that by not documenting and maintaining the Operating Plan(s) to minimize forecasted Energy Emergencies as identified in the near-term Energy Reliability Assessment, including provisions for notifying the Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s) 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 BAL-007-1, Requirement R3			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	The Balancing Authority documented an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs.

VSL Justifications for BAL-007-1, Requirement R3	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R4	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that near-term Energy Reliability Assessments were not performed according to the process documented in Requirement R1 using the scenarios or methods documented in Requirement R2 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 BAL-007-1, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to perform a Near-Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.

VSL Justifications for BAL-007-1, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R5	
Proposed VRF	**Medium**
NERC VRF Discussion	A VRF of Medium is appropriate due to the fact that if an Operating Plan(s) was not implemented once a near-term Energy Reliability Assessment identified one or more forecasted Energy Emergencies it 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 BAL-007-1, Requirement R5			
Lower	**Moderate**	**High**	**Severe**
N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a Near-Term ERA identified any of the forecasted conditions in Requirement R5.

VSL Justifications for BAL-007-1, Requirement R5	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed 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 VSL is Severe, as any degree of noncompliant performance would result in totally or mostly missing the reliability intent of the requirement. The proposed VSL does not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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 BAL-007-1, Requirement R6	
Proposed VRF	**Low**
NERC VRF Discussion	A VRF of low is appropriate due to the administrative nature of the Balancing Authority providing the Reliability Coordinator with its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3.
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 low 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 low VRF requirement per the criteria filed with FERC as part of the ERO's Sanctions Guidelines.
FERC VRF G5 Discussion Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation	This requirement does not mingle a higher risk reliability objective and a lesser risk reliability objective. Therefore, the VRF reflects the risk of the whole requirement.

VSLs for BAL-007-1, Requirement R6

Lower	Moderate	High	Severe
N/A	N/A	The Balancing Authority reviewed information that contained the Near-Term ERAs process, the Scenarios or methods, and Operating Plan(s) but failed to update within 24 months.	The Balancing Authority failed to review, update, and provide the Near-Term ERAs process, the Scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.

VSL Justifications for BAL-007-1, Requirement R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement is new. Therefore, the proposed VSLs do not have the unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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-003-6

VRF Justification for TOP-003-7, Requirement R2

The VRF did not change from the previously FERC approved TOP-003-6 Reliability Standard. The modifications made to R2 are similar in content to the previous draft and therefore the VRF remained low.

VSL Justification for TOP-003-7, Requirement R2

Please refer to the VSL table located below.

VRF Justification for TOP-003-7, Requirement R4

The VRF did not change from the previously FERC approved TOP-003-6 Reliability Standard. The modifications made to R4 are similar in content to the previous draft and therefore the VRF remained low.

VSL Justification for TOP-003-7, Requirement R4

Please refer to the VSL table located below.

VSLs for TOP-003-7, Requirement R2			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not include two or fewer of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include three of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include four of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not include any of the parts (Part 2.1 through Part 2.5) of the documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments. OR, The Balancing Authority did not

			have a documented specification(s) for the data and information necessary for it to perform its analysis functions, Real- time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-7, Requirement R2	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional assessment to Requirement R2. The proposed VSL was modified to reflect the additional assessment. It does not have unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, therefore, consistent with the requirement.

VSL Justifications for TOP-003-7, Requirement R2	
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.

VSLs for TOP-003-7, Requirement R4			
Lower	**Moderate**	**High**	**Severe**
The Balancing Authority did not distribute its Specification(s) to one entity, or 5% or less of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to two entities, or more than 5% and less than or equal to 10% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to three entities, or more than10% and less than or equal to 15% of the entities, whichever is greater, that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.	The Balancing Authority did not distribute its Specification(s) to four or more entities, or more than 15% of the entities that have data and information required by the Balancing Authority's analysis functions, Real-time monitoring, and Near-Term Energy Reliability Assessments.

VSL Justifications for TOP-003-7, Requirement R4	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The requirement was modified by adding an additional assessment to Requirement R4. The proposed VSL was modified to reflect the additional assessment. It does not have unintended consequence of lowering the level of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties <u>Guideline 2a</u>: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent <u>Guideline 2b</u>: Violation Severity Level Assignments that Contain Ambiguous Language	The proposed VSLs are not binary and do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The proposed VSL uses the same terminology as used in the associated requirement and is, 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.

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

The BAL-007-1 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024
45-day formal comment period with additional ballot	May 7 – June 20, 2024
45-day formal or informal comment period with additional ballot	September 19 – November 4, 2024

Anticipated Actions	Date
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 10, 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Near-term Energy Reliability Assessments
2. **Number:** BAL-007-1
3. **Purpose:** To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.
4. **Applicability:**

    4.1. Functional Entities:

    4.1.1. Balancing Authority

5. **Effective Date:** See Implementation Plan for BAL-007-1.

B. Requirements and Measures

R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a process for conducting Near-Term Energy Reliability Assessments (ERA). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The Near-Term ERA process shall account for:

1.1.1. Forecasted or assumed Demand profiles;

1.1.2. Resource capabilities and operational limitations, including fuel supply;

1.1.3. Energy transfers with other Balancing Authorities; and

1.1.4. Known Bulk Electric System (BES) Transmission constraints that limit the ability of generation to deliver their output to Load.

1.2. The Near-Term ERA process shall specify the duration of the Balancing Authority's Near-Term ERAs.

1.3. The Near-Term ERA process shall specify the frequency at which the Balancing Authority will conduct Near-Term ERAs, subject to the following:

1.3.1. Each Balancing Authority will conduct Near-Term ERAs for all time periods unless the Balancing Authority demonstrates, via a documented methodology, that a Near-Term ERA is not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s).

1.3.2. The documented methodology for identifying time periods for which the Balancing Authority will not conduct a Near-Term ERA must (i) define the criteria used to determine when there is a low risk of an Energy Emergency occurring, and (ii) account for the items listed in 1.1.1 – 1.1.4 and other conditions associated with Energy Emergencies.

M1. Each Balancing Authority shall have evidence that it documented a process for conducting Near-Term ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a set of Scenarios, or a method for developing Scenarios, for use in performing Near-Term ERAs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. The set of Scenarios must include (i) a base Scenario with expected system conditions, and (ii) other Scenarios that stress the system due to the following conditions, as applicable to the Balancing Authority's system:

2.1.1. Higher than forecasted or assumed Demand profiles;

2.1.2. The effects of an energy supply contingency;

2.1.3. The effects of a fuel supply contingency; and

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.

M2. Each Balancing Authority shall have evidence that it documented the Scenarios, or the method of developing Scenarios, for use in performing Near-Term ERAs.

R3. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document one or more Operating Plan(s) to implement in response to forecasted Energy Emergencies, including provisions for notification to their Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it documented its Operating Plan(s) in accordance with Requirement R3.

R4. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, perform Near-Term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall have evidence that it performed the Near-Term ERAs in accordance with Requirement R4.

R5. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, implement its Operating Plan(s), as documented in Requirement R3, when Near-Term ERAs identify any of the following forecasted Energy Emergencies: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B; or
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B.

M5. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) in accordance with Requirement R5.

R6. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, review, update, as necessary, and provide to the applicable Reliability Coordinator its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3, at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have evidence that it reviewed and provided its Near-term ERA process, Scenarios or methods, and Operating Plan(s) to its Reliability Coordinator, in accordance with Requirement R6.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Balancing Authority shall keep data or evidence to show compliance with applicable requirements for six months for Near-Term ERAs or since the last audit.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
R1.	N/A	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 or Part 1.2.	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 through Part 1.2. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for one of the elements in Requirement R1 Part 1.3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.
R2.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include one of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include two of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include three of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include any of the conditions listed in Requirement R2 Part 2.1. OR The Balancing Authority failed to document a set of Scenarios or a method of developing

				Scenarios for use in performing Near-Term ERAs.
R3.	N/A	N/A	The Balancing Authority documented an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs.
R4.	N/A	N/A	N/A	The Balancing Authority failed to perform a Near-Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.
R5.	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a Near-Term ERA identified any of the forecasted conditions in Requirement R5.
R6.	N/A	N/A	The Balancing Authority reviewed information that contained the Near-Term ERAs process, the Scenarios or methods, and Operating	The Balancing Authority failed to review, update, and provide the Near-Term ERAs process, the Scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.

			Plan(s) but failed to update within 24 months.	

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan
- NERC Project 2022-03 Technical Rationale
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
1	TBD	NERC Project 2022-03 energy assurance new standard.	New

Standard Development Timeline

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

Description of Current Draft

The BAL-007-1 is posted for a 10-day final ballot.

Completed Actions	Date
Standards Committee approved Standard Authorization Request (SAR) for posting	June 15, 2022
SAR posted for comment	June 22, 2022 – July 21, 2022
45-day formal comment period with initial ballot	January 25, 2024 – March 11, 2024
45-day formal comment period with additional ballot	May 7 – June 20, 2024
45-day formal or informal comment period with additional ballot	September 19 – November 4, 2024

Anticipated Actions	Date
10-day final ballot	November 25 – December 4, 2024
Board adoption	December 10, 2024

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

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

Term(s):

Energy Reliability Assessment (ERA) – Assessment of the resources necessary to reliably supply the Electrical Energy required to serve Demand and to provide Operating Reserves for the Bulk Power System throughout the associated assessment period.

Near-Term Energy Reliability Assessment – An Energy Reliability Assessment with an assessment period that begins no later than two days after the operating day and has a minimum duration of five days and a maximum duration of six weeks.

A. Introduction

1. **Title:** Near-term Energy Reliability Assessments
2. **Number:** BAL-007-1
3. **Purpose:** To assess, report, and plan to address forecasted Energy Emergencies in the near-term time horizon.
4. **Applicability:**
    - **4.1. Functional Entities:**
        - **4.1.1.** Balancing Authority
5. **Effective Date:** See Implementation Plan for BAL-007-1.

B. Requirements and Measures

R1. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a process for conducting Near-Term Energy Reliability Assessments (ERA). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

1.1. The Near-Term ERA process shall account for:

1.1.1. Forecasted or assumed Demand profiles;

1.1.2. Resource capabilities and operational limitations, including fuel supply;

1.1.3. Energy transfers with other Balancing Authorities; and

1.1.4. Known Bulk Electric System (BES) Transmission constraints that limit the ability of generation to deliver their output to Load.

1.2. The Near-Term ERA process shall specify the duration of the Balancing Authority's Near-Term ERAs.

1.3. The Near-Term ERA process shall specify the frequency at which the Balancing Authority will conduct Near-Term ERAs, subject to the following:

1.3.1. Each Balancing Authority will conduct Near-Term ERAs for all time periods unless the Balancing Authority demonstrates, via a documented methodology, that a Near-Term ERA is not necessary for a specified time period(s) because there is a low risk of an Energy Emergency occurring during that specified time period(s).

1.3.2. The documented methodology for identifying time periods for which the Balancing Authority will not conduct a Near-Term ERA must (i) define the criteria used to determine when there is a low risk of an Energy Emergency occurring, and (ii) account for the items listed in 1.1.1 – 1.1.4 and other conditions associated with Energy Emergencies.

M1. Each Balancing Authority shall have evidence that it documented a process for conducting Near-Term ERAs in accordance with Requirement R1.

R2. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document a set of Scenarios, or a method for developing Scenarios, for use in performing Near-Term ERAs. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

2.1. The set of Scenarios must include (i) a base Scenario with expected system conditions, and (ii) other Scenarios that stress the system due to the following conditions, as applicable to the Balancing Authority's system:

2.1.1. Higher than forecasted or assumed Demand profiles;

2.1.2. The effects of an energy supply contingency;

2.1.3. The effects of a fuel supply contingency; and

2.1.4. Other stressed conditions that have a historical precedent of occurring, as defined by the Balancing Authority, based on the information available at the time of Scenario development.

M2. Each Balancing Authority shall have evidence that it documented the Scenarios, or the method of developing Scenarios, for use in performing Near-Term ERAs.

R3. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, document one or more Operating Plan(s) to implement in response to forecasted Energy Emergencies, including provisions for notification to their Reliability Coordinator of the forecasted Energy Emergency and the Operating Plan(s). *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M3. Each Balancing Authority shall have evidence that it documented its Operating Plan(s) in accordance with Requirement R3.

R4. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, perform Near-Term ERAs according to the process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

M4. Each Balancing Authority shall have evidence that it performed the Near-Term ERAs in accordance with Requirement R4.

R5. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, implement its Operating Plan(s), as documented in Requirement R3, when Near-Term ERAs identify any of the following forecasted Energy Emergencies: *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

- Forecasted EEA2 circumstances as defined in EOP-011 Attachment 1 Section B; or
- Forecasted EEA3 circumstances as defined in EOP-011 Attachment 1 Section B.

M5. Each Balancing Authority shall have evidence that it has implemented an Operating Plan(s) in accordance with Requirement R5.

R6. Each Balancing Authority shall, individually or jointly with other Balancing Authorities, review, update, as necessary, and provide to the applicable Reliability Coordinator its Near-term ERA process, Scenarios or methods, and Operating Plan(s), documented under Requirements R1 through R3, at least once every 24 calendar months. *[Violation Risk Factor: Low] [Time Horizon: Operations Planning]*

M6. Each Balancing Authority shall have evidence that it reviewed and provided its Near-term ERA process, Scenarios or methods, and Operating Plan(s) to its Reliability Coordinator, in accordance with Requirement R6.

C. Compliance

1. **Compliance Monitoring Process**

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

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

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

   - The Balancing Authority shall keep data or evidence to show compliance with applicable requirements for six months for Near-Term ERAs or since the last audit.

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

Violation Severity Levels

R #	Violation Severity Levels			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 or Part 1.2.	The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for the elements in Requirement R1 Part 1.1 through Part 1.2. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for one of the elements in Requirement R1 Part 1.3.	The Balancing Authority failed to document an Energy Reliability Assessment process for the Near-Term ERAs. OR The Balancing Authority documented an Energy Reliability Assessment process for the Near-Term ERAs but did not account for any of the elements in Requirement R1 Part 1.3.
R2.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include one of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include two of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include three of the conditions listed in Requirement R2 Part 2.1.	The Balancing Authority documented a set of Scenarios or a method of developing Scenarios but did not include any of the conditions listed in Requirement R2 Part 2.1. OR The Balancing Authority failed to document a set of Scenarios or a method of developing

				Scenarios for use in performing Near-Term ERAs.
R3.	N/A	N/A	The Balancing Authority documented an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs but failed to include provisions for notification to the Reliability Coordinator.	The Balancing Authority failed to document an Operating Plan(s) to implement in response to forecasted Energy Emergencies as identified in the Near-Term ERAs.
R4.	N/A	N/A	N/A	The Balancing Authority failed to perform a Near-Term ERA in accordance with its process documented in Requirement R1 using the Scenarios or methods documented in Requirement R2.
R5.	N/A	N/A	N/A	The Balancing Authority failed to implement an Operating Plan(s) when a Near-Term ERA identified any of the forecasted conditions in Requirement R5.
R6.	N/A	N/A	The Balancing Authority reviewed information that contained the Near-Term ERAs process, the Scenarios or methods, and Operating	The Balancing Authority failed to review, update, and provide the Near-Term ERAs process, the Scenarios or methods, and Operating Plan(s) to the Reliability Coordinator.

			Plan(s) but failed to update within 24 months.	

D. Regional Variances

None.

E. Associated Documents

- Implementation Plan
- NERC Project 2022-03 Technical Rationale
- NERC Project 2022-03 Project Page

Version History

Version	Date	Action	Change Tracking
1	TBD	NERC Project 2022-03 energy assurance new standard.	New

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2022-03 Energy Assurance with Energy-Constrained Resources

Final Ballots Open through December 4, 2024

Now Available

The final ballots for **BAL-007-1 Near-term Energy Reliability Assessments**, **TOP-003-7 Transmission Operator and Balancing Authority Data and Information Specification and Collection,** and their implementation plans are open through **8 p.m. Eastern, Wednesday, December 4, 2024**.

Balloting
In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

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

Next Steps
The voting results will be posted and announced after the ballots close. If approved, the standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at 404-479-7358.

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

BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 TOP-003-7 FN 2 ST
Voting Start Date: 11/25/2024 8:10:31 AM
Voting End Date: 12/4/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 226
Total Ballot Pool: 260
Quorum: 86.92
Quorum Established Date: 11/25/2024 2:27:11 PM
Weighted Segment Value: 93.25

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	73	1	51	0.927	4	0.073	0	13	5
Segment: 2	8	0.8	8	0.8	0	0	0	0	0
Segment: 3	64	1	45	0.918	4	0.082	0	5	10
Segment: 4	15	1	11	1	0	0	0	1	3
Segment: 5	57	1	31	0.861	5	0.139	0	8	13
Segment: 6	38	1	28	0.875	4	0.125	0	3	3
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	260	6.2	178	5.782	17	0.418	0	31	34

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		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	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
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	None	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Affirmative	N/A
1	JEA	Joseph McClung		Negative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle 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. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Negative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Seattle City Light	Michael Jang		Affirmative	N/A
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	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Wolverine Power Supply Cooperative, Inc.	Andrew Anderson		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	CPS Energy	Juan Gomez		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		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
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Georgia System Operations Corporation	Scott McGough		None	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Negative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lakeland Electric	Steven Marshall		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		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	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	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	Negative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seattle City Light	Zenon O'young-Chu		Affirmative	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Abstain	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	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	Wabash Valley Power Association	Scott Berry		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	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Abstain	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seattle City Light	Robert Jones		Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Affirmative	N/A
4	Western Power Pool	Kevin Conway		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	Arevon Energy	Srinivas Kappagantula		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Christine Jennings		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		None	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Negative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	None	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A
5	JEA	John Babik		Negative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Abstain	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		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		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		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	Talen Generation, LLC	Donald Lock		Negative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		None	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seattle City Light	Daren Brubaker		Affirmative	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	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		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources | Draft 1 Implementation Plan FN 2 OT
Voting Start Date: 11/25/2024 1:10:35 PM
Voting End Date: 12/4/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 2
Total # Votes: 221
Total Ballot Pool: 254
Quorum: 87.01
Quorum Established Date: 11/25/2024 2:26:34 PM
Weighted Segment Value: 85.56

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	72	1	45	0.833	9	0.167	0	14	4
Segment: 2	7	0.7	7	0.7	0	0	0	0	0
Segment: 3	62	1	37	0.787	10	0.213	0	6	9
Segment: 4	14	1	9	0.9	1	0.1	0	1	3
Segment: 5	57	1	29	0.806	7	0.194	0	8	13
Segment: 6	37	1	23	0.793	6	0.207	0	4	4
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	4	0.4	0	0	0	1	0
Totals:	254	6.1	154	5.219	33	0.881	0	34	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		Affirmative	N/A
1	American Transmission Company, LLC	Amy Wilke		None	N/A
1	APS - Arizona Public Service Co.	Daniela Atanasovski		Negative	N/A
1	Arizona Electric Power Cooperative, Inc.	Jennifer Bray		Affirmative	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		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	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	N/A
1	Duke Energy	Katherine Street		Negative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	FirstEnergy - FirstEnergy Corporation	John Martinez		Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Affirmative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic		Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Negative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Negative	N/A
1	JEA	Joseph McClung		Negative	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Manitoba Hydro	Nazra Gladu		Affirmative	N/A
1	Minnkota Power Cooperative Inc.	Theresa Allard	Nikki Carson-Marquis	Affirmative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker	Tammy Porter	None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Bob Cardle	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Abstain	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle 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. 2 of Grant County, Washington	Joanne Anderson		Affirmative	N/A
1	Puget Sound Energy, Inc.	Anna Lavik		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Laura Somak	Israel Perez	Negative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
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	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Abstain	N/A
1	VELCO -Vermont Electric Power Company, Inc.	Randall Buswell		Abstain	N/A
1	Wolverine Power Supply Cooperative, Inc.	Andrew Anderson		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		None	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	N/A
3	Buckeye Power, Inc.	Tom Schmidt	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	CPS Energy	Juan Gomez		Abstain	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Negative	N/A
3	JEA	Marilyn Williams		Negative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		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	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	None	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Bob Cardle	Abstain	N/A
3	Platte River Power Authority	Richard Kiess		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	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	Negative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	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	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	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	Wabash Valley Power Association	Scott Berry		None	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		Affirmative	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	Georgia System Operations Corporation	Katrina Lyons		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Negative	N/A
4	Western Power Pool	Kevin Conway		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		Negative	N/A
5	Arevon Energy	Srinivas Kappagantula		None	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Christine Jennings		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		None	N/A
5	DTE Energy - Detroit Edison Company	Mohamad Elhusseini		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		Affirmative	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Grid Strategies LLC	Michael Goggin		None	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Negative	N/A
5	Invenergy LLC	Rhonda Jones		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	JEA	John Babik		Negative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Bob Cardle	Abstain	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		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		None	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		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	Talen Generation, LLC	Donald Lock		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		None	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Affirmative	N/A
6	Invenergy LLC	Colin Chilcoat		None	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		Abstain	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	Public Utility District No. 1 of Chelan County	Tamarra Hardie		Affirmative	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Snohomish County PUD No. 1	John Liang		None	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Affirmative	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2022-03 Energy Assurance with Energy-Constrained Resources BAL-007-1 FN 4 ST
Voting Start Date: 11/25/2024 8:59:06 AM
Voting End Date: 12/4/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 4
Total # Votes: 235
Total Ballot Pool: 265
Quorum: 88.68
Quorum Established Date: 11/25/2024 2:27:22 PM
Weighted Segment Value: 81.31

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	49	0.845	9	0.155	0	14	3
Segment: 2	8	0.8	7	0.7	1	0.1	0	0	0
Segment: 3	58	1	39	0.83	8	0.17	0	4	7
Segment: 4	9	0.7	5	0.5	2	0.2	0	0	2
Segment: 5	63	1	35	0.814	8	0.186	0	8	12
Segment: 6	44	1	27	0.771	8	0.229	0	3	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	265	6.1	167	4.96	37	1.14	0	31	30

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		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		None	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Negative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	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	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	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		Negative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		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		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	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		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		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	Broc Bruton	Abstain	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	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Negative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Negative	N/A
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Affirmative	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		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
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Florida Municipal Power Agency	Navid Nowakhtar	LaKenya Vannorman	None	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	JEA	Marilyn Williams		Negative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Negative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		None	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Negative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	N/A
3	Santee Cooper	Vicky Budreau		Negative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Negative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	N/A
3	Tennessee Valley Authority	Ian Grant		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	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Negative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Affirmative	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Christine Jennings		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	Calpine Corporation	Whitney Wallace		Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Negative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Negative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Affirmative	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	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		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pattern Operators LP	George E Brown		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Abstain	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Negative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Negative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	N/A
5	Santee Cooper	Carey Salisbury		Negative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	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	Talen Generation, LLC	Donald Lock		Negative	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Abstain	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Negative	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Negative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	N/A
6	Santee Cooper	Marty Watson		Negative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Negative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	Negative	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: 2022-03 Energy Assurance with Energy-Constrained Resources Implementation Plan FN 4 OT
Voting Start Date: 11/25/2024 1:12:09 PM
Voting End Date: 12/4/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 4
Total # Votes: 229
Total Ballot Pool: 257
Quorum: 89.11
Quorum Established Date: 11/25/2024 2:26:48 PM
Weighted Segment Value: 86.76

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	51	0.879	7	0.121	0	14	3
Segment: 2	8	0.7	6	0.6	1	0.1	0	0	1
Segment: 3	54	1	38	0.826	8	0.174	0	4	4
Segment: 4	9	0.7	7	0.7	0	0	0	0	2
Segment: 5	59	1	34	0.872	5	0.128	0	8	12
Segment: 6	44	1	29	0.829	6	0.171	0	3	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	1	0	0	0	0	0	0	1	0
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	7	0.6	5	0.5	1	0.1	0	1	0
Totals:	257	6	170	5.206	28	0.794	0	31	28

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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Affirmative	N/A
1	Ameren - Ameren Services	Tamara Evey		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		None	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	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Affirmative	N/A
1	Colorado Springs Utilities	Corey Walker		Abstain	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
1	Dominion - Dominion Virginia Power	Steven Belle		Negative	N/A
1	Duke Energy	Katherine Street		Affirmative	N/A
1	Edison International - Southern California Edison Company	Robert Blackney		Affirmative	N/A
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Hayden Maples	Affirmative	N/A
1	Eversource Energy	Joshua London		Affirmative	N/A
1	Exelon	Daniel Gacek		Affirmative	N/A
1	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	Chantal Mazza	Negative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Allie Gavin	Abstain	N/A
1	JEA	Joseph McClung		Negative	N/A
1	Lakeland Electric	Larry Watt		Affirmative	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		Negative	N/A
1	Lower Colorado River Authority	Matt Lewis		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	LS Power Transmission, LLC	Jennifer Richardson		None	N/A
1	M and A Electric Power Cooperative	William Price		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		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Abstain	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	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		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		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	Broc Bruton	Abstain	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	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	Portland General Electric Co.	Brooke Jockin		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Matthew Jaramilla	Israel Perez	Negative	N/A
1	Santee Cooper	Chris Wagner		Negative	N/A
1	SaskPower	Wayne Guttormson		Abstain	N/A
1	Sho-Me Power Electric Cooperative	Olivia Olson		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Abstain	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		None	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	N/A
2	Independent Electricity System Operator	Helen Lainis		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	Keith Jonassen	Affirmative	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		Affirmative	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Affirmative	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Abstain	N/A
3	Ameren - Ameren Services	David Jendras Sr	Danielle Moskop	Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		None	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Negative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Abstain	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Negative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Affirmative	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	Affirmative	N/A
3	Eversource Energy	Vicki O'Leary		Negative	N/A
3	Exelon	Kinte Whitehead		Affirmative	N/A
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	JEA	Marilyn Williams		Negative	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	Fausto Serratos		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Affirmative	N/A
3	MGE Energy - Madison Gas and Electric Co.	Benjamin Widder		Affirmative	N/A
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		None	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Affirmative	N/A
3	NextEra Energy - Florida Power and Light Co.	Karen Demos		Affirmative	N/A
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	Orlando Utilities Commission	Ballard Mutters		None	N/A
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Affirmative	N/A
3	Portland General Electric Co.	Mayra Franco		Affirmative	N/A
3	PPL - Louisville Gas and Electric Co.	James Frank		Affirmative	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Affirmative	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	N/A
3	Santee Cooper	Vicky Budreau		Negative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		None	N/A
3	Tennessee Valley Authority	Ian Grant		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	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	DTE Energy	Patricia Ireland		Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	None	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Public Utility District No. 2 of Grant County, Washington	Karla Weaver		None	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	WEC Energy Group, Inc.	Candace Morakinyo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	AEP	Thomas Foltz		Abstain	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		None	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Christine Jennings		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier	Carly Miller	Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	Calpine Corporation	Whitney Wallace		Affirmative	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Abstain	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	Electric Power Supply Association	Bill Zuretti		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz	Joseph Knight	None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Abstain	N/A
5	Hydro-Quebec (HQ)	Junji Yamaguchi	Chantal Mazza	Negative	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		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		None	N/A
5	Manitoba Hydro	Kristy-Lee Young		Affirmative	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
5	National Grid USA	Robin Berry		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Affirmative	N/A
5	NextEra Energy	Richard Vendetti		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Affirmative	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		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Affirmative	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Public Utility District No. 2 of Grant County, Washington	Loren Harbachuk		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Negative	N/A
5	Santee Cooper	Carey Salisbury		Negative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	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	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		None	N/A
6	AEP	Mathew Miller		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	N/A
6	Cleco Corporation	Robert Hirchak		Negative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco		Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	N/A
6	Duke Energy	John Sturgeon		Affirmative	N/A
6	Edison International - Southern California Edison Company	Stephanie Kenny		Affirmative	N/A
6	Entergy	Julie Hall		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Evergy	Tiffany Lake	Hayden Maples	Affirmative	N/A
6	Florida Municipal Power Agency	Jade Bulitta	LaKenya Vannorman	None	N/A
6	Great River Energy	Brian Meloy		Affirmative	N/A
6	Imperial Irrigation District	Diana Torres	Denise Sanchez	Affirmative	N/A
6	Lakeland Electric	Paul Shipps		Affirmative	N/A
6	Lincoln Electric System	Eric Ruskamp		None	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Negative	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		None	N/A
6	New York Power Authority	Shelly Dineen		Affirmative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Abstain	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		None	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Negative	N/A
6	Santee Cooper	Marty Watson		Negative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Affirmative	N/A
6	Western Area Power Administration	Jennifer Neville		Affirmative	N/A
6	Xcel Energy, Inc.	Steve Szablya		None	N/A
8	Florida Reliability Coordinating Council – Member Services Division	Vince Ordax		Abstain	N/A
10	Midwest Reliability Organization	Mark Flanary		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	ReliabilityFirst	Tremayne Brown	Greg Sorenson	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		Negative	N/A

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NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit G

Standard Drafting Team Roster

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Drafting Team Roster

Project 2022-03 Energy Assurance with Energy-Constrained Resources

	Name	Entity
Chair	David Mulcahy	Illuminate Power Analytics, LLC
Vice Chair	Ruth Kloecker	ITC Holdings
Member	Mike Knowland	New England Independent System Operator
	Julie Jin	ERCOT
	John Stevenson	New York Independent System Operator
	John Brewer	United States Department of Energy
	Layne Brown	WECC
	Mark Kuras	PJM Interconnection, LLC
	Phillip Wiginton	Tennessee Valley Authority
	Derek Hawkins	Southwest Power Pool, Inc.
	Sean Boyle	Constellation Energy
	Brent Duncan	Southern Company Service, Inc.
	Clyde Loutan	California Independent System Operator
PMOS Liaison	Joseph Gatten	Xcel Energy
	Terri Pyle	OGE
NERC Staff	Jordan Mallory, Sr. Standards Developer	North American Electric Reliability Corporation

	Name	Entity
	Dominique Love, Standards Developer	North American Electric Reliability Corporation
	Elsa Prince, Technical Advisor	North American Electric Reliability Corporation
	Shamai Elstein, Counsel	North American Electric Reliability Corporation
	Kiel Lyons, Compliance	North American Electric Reliability Corporation