UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD CIP-002-8

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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") regulations,[2] the North American Electric Reliability Corporation ("NERC")[3] hereby submits for Commission approval proposed Reliability Standard CIP-002-8 – Cyber Security – BES Cyber System Categorization. Proposed Reliability Standard CIP-002-8 would advance reliability by revising the "bright-line" criteria for applicable Transmission Owners and Transmission Operators to categorize their BES Cyber Systems based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System ("BES"). Specifically, the proposed changes discussed herein would benefit reliability by: (1) modifying the Control Center definition to include certain Transmission Owners that have the ability to control transmission Facilities; (2) revising Attachment 1 to address the categorization of Transmission Owner Control Centers; and (3) revising Attachment 1 to replace the language "perform the functional obligations of" with reference to "reliability tasks" as included in the Control Center definition or, in the case of the

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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].

Transmission Operator or Transmission Owner, reference to the Control Center definition with respect to "reliability tasks" or "capability to control transmission Facilities", as appropriate.[4]

NERC requests that the Commission approve the proposed Reliability Standard, provided in **Exhibit A** hereto, as just, reasonable, not unduly discriminatory or preferential, and in the public interest. NERC also requests approval of: (1) the associated Implementation Plan (**Exhibit B**); the associated Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs"), which remain unchanged from the VRFs and VSLs proposed in Reliability Standard CIP-002-7, which is pending FERC approval[5] (**Exhibit A**); and the retirement of Reliability Standard CIP-002-7.

As required by Section 39.5(a) of the Commission's regulations,[6] this petition presents the technical basis and purpose of the proposed Reliability Standard, a summary of the development history (**Exhibit E**), and a demonstration that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[7] (**Exhibit C**). The NERC Board of Trustees adopted the proposed Reliability Standard on December 10, 2024.

I. SUMMARY

NERC's suite of cyber security Critical Infrastructure Protection ("CIP") Reliability Standards seeks to mitigate cyber security risks to BES Facilities, systems, and equipment. CIP Reliability Standards apply protections to BES Cyber Systems based on their impact to the BES if

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4 Unless otherwise indicated, all capitalized terms used in this petition shall have the meaning set forth in the Glossary of Terms used in NERC Reliability Standards [hereinafter NERC Glossary], https://www.nerc.com/pa/Stand/Glossary%20ofTerms/Glossary-of-Terms.pdf.

5 *See Petition of the N. Am. Elec. Reliability Corp. for Approval of Critical Infrastructure Protection Reliability Standards*, Docket No. RM24-8-000 (July 10, 2024).

6 18 C.F.R. § 39.5(a).

7 *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).

rendered unavailable, degraded, or misused. This framework[8] requires that Responsible Entities[9] categorize BES Cyber Systems as low, medium, or high impact based on the characteristics of their BES Facilities.

Consistent with prior CIP-002 versions, the purpose of proposed Reliability Standard CIP-002-8 is to identify and categorize BES Cyber Systems and their associated assets as low, medium, or high impact. Attachment 1 of proposed Reliability Standard CIP-002-8 includes the impact rating criteria for determining the assigned impact level for BES Cyber Systems, which is fundamental for determining the applicability of the suite of CIP Reliability Standards.

Proposed Reliability Standard CIP-002-8 would enhance reliability by providing for improved risk identification, which in turn would allow Responsible Entities to focus resources on protecting assets that pose a higher risk to reliability if unavailable, degraded, or compromised. To address these risks, the drafting team proposes to revise the definition of Control Center to include certain Transmission Owners that have the ability to control transmission Facilities.

The drafting team further seeks to modify Criterion 2.12 of Attachment 1 by revising the "bright-line" criteria for Transmission Owners and Transmission Operators to categorize their BES Cyber Systems. The proposed revisions would address the categorization of Transmission Owner Control Centers that have the capability to control transmission Facilities and thus perform the functional obligations of a Transmission Operator. The proposed revisions would also clarify the language "perform the functional obligations of" by instead referencing the "reliability tasks" performed by those same Registered Entities or, in the case of the Transmission Operator and the

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8 This framework categorizing BES Cyber Systems into high, medium, and low impact was established in the "Version 5" Reliability Standards that became effective in the United States in 2016. "Version 5" Reliability Standards refer to CIP-002-5.1a, CIP-003-5, CIP-004-5, CIP-005-5, CIP-006-5, CIP-007-5, CIP-008-5, CIP-009-5. CIP-009-5, CIP-010-1, and CIP-001-1.

9 As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

Transmission Owner, reference to the Control Center definition with respect to "reliability tasks" or "capability to control transmission Facilities", as appropriate.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[10]

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[11] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the Bulk-Power System ("BPS"), and with the duty of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1) of the FPA states that all users, owners, and operators of the BPS in the United States will be subject to Commission-approved Reliability Standards.[12] Section 215(d)(5) of the FPA authorizes the

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

[11] 16 U.S.C. § 824o.

[12] *Id.* § 824(b)(1).

Commission to order the ERO to submit a new or modified Reliability Standard.[13] 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.[14]

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the BPS 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.[15]

B. NERC Reliability Standards Development Procedure

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[16] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[17]

In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards, and thus satisfies several of the Commission's criteria for approving Reliability Standards.[18] The development process is open to any person or

[13] *Id.* § 824o(d)(5).
[14] 18 C.F.R. § 39.5(a).
[15] 16 U.S.C. § 824o(d)(2); 18 C.F.R. § 39.5(c)(1).
[16] Order No. 672, *supra*, at P 334.
[17] The NERC Rules of Procedure are available at https://www.nerc.com/AboutNERC/Pages/Rules-of-Procedure.aspx. The NERC Standard Processes Manual is available at https://www.nerc.com/AboutNERC/RulesOfProcedure/Appendix_3A_SPM_Clean_Mar2019.pdf.
[18] ERO Certification Order, *supra*, at P 250.

entity with a legitimate interest in the reliability of the BPS. 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. CIP Version 5 Transition Program Recommendations

In 2013, NERC initiated the CIP Version 5 Transition Program in collaboration with industry stakeholders and Regional Entities to assist Responsible Entities with the implementation of the "Version 5" CIP Reliability Standards.[19] As part of this program, industry volunteers participated in an implementation study under which they would adopt the Version 5 standards prior to their effective date.[20] NERC worked with the industry implementation study participants, Regional Entity staff, and FERC staff to develop lessons learned from early implementation of the Version 5 standards. Throughout 2014 and 2015 the Version 5 Transition Advisory Group ("V5 TAG") developed documents with the lessons learned and frequently asked questions.[21] The V5 TAG also identified implementation issues that would best be addressed through standards revisions.[22]

Among other things, the V5 TAG recommended clarifying certain language in Attachment 1 to CIP-002-5.1a. Specifically, the V5 TAG suggested revisions to the language italicized below within medium impact Criterion 2.12 of CIP-002-5.1a:

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[19] *See supra* note 8.

[20] NERC, *Implementation Study Final Report – CIP Version 5 Transition Program* (Oct. 2014), https://www.nerc.com/pa/ci/tpv5impmntnstdy/cipv5_implem_study_final_report_oct2014.pdf.

[21] The V5 TAG lessons learned and frequently asked questions documents are available at https://www.nerc.com/pa/CI/Pages/Transition-Program-V5-Implementation-Study.aspx.

[22] NERC, CIP V5 Issues for Standard Drafting Team Consideration (Sept. 15, 2015), https://www.nerc.com/pa/stand/project%20201602%20modifications%20to%20cip%20standards%20dl/transfer_issues_v5tag-sdt_1st-final-03232016.pdf.

> Each Control Center or backup Control Center *used to perform the functional obligations of* the Transmission Operator not included in High Impact Rating (H), above. [emphasis added]

The V5 TAG observed that the phrase "used to perform the functional obligation of" was particularly unclear for Transmission Owners who may only operate limited breakers for assets containing low impact BES Cyber Systems. Under the Criterion 2.12 language in CIP-002-5.1a, these Transmission Owners' Control Centers could be considered to contain medium impact BES Cyber Systems despite operating a few assets with low impact BES Cyber Systems. The V5 TAG determined that this language in CIP-002-5.1a should be clarified.

D. Project 2021-03 CIP-002

In 2020, NERC filed proposed Reliability Standard CIP-002-6 for Commission approval. In proposed Reliability Standard CIP-002-6, NERC proposed revisions to Criterion 2.12 of Attachment 1 to address recommendations by the V5 TAG.[23] On February 4, 2021, the NERC Board of Trustees withdrew its adoption of proposed Reliability Standard CIP-002-6, stating that recent cybersecurity events and the evolving threat landscape warranted additional caution regarding any criteria language that may permit more entities to categorize BES Cyber Systems as low impact and, therefore subject to fewer requirements in the suite of CIP Reliability Standards.[24] The NERC Board of Trustees also directed NERC staff to work with stakeholders to conduct further study of the risks presented by various facilities that meet the criteria that define low impact cyber facilities and report on whether those criteria should be modified. On February 5, 2021,

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[23] *Petition of NERC for Approval of Proposed Reliability Standard CIP-002-6*, Docket No. RM20-17-000 (June 12, 2020).

[24] *See* NERC Board of Trustees February 4, 2021 Meeting Minutes, at pp. 7-8, https://www.nerc.com/gov/bot/Agenda%20highlights%20and%20Mintues%202013/Minutes%20-%20BOT%20Open%20-%20Feb%204%202021.pdf.

NERC filed a Notice of Withdrawal of Proposed Reliability Standard CIP-002-6[25] so that NERC could reevaluate the criterion based on additional data and studies.[26]

In response to the V5 TAG recommendations and the NERC Board of Trustees directive, the Standards Committee, at its March 17, 2021 meeting, assigned a portion of the Project 2016-02 Standard Authorization Request ("SAR") to the Project 2021-03 CIP-002 Transmission Owner Control Centers drafting team.[27] In response to the directive and the scope of the SAR, the drafting team initiated a field test, consistent with Section 6.0 of the Standard Processes Manual. The Standards Committee approved the Project 2021-03 Field Test Plan on November 17, 2021. The drafting team engaged with field test participants to conduct the field test in 2022, and the final report was posted to the project page in January 2023.[28]

The CIP-002 Transmission Owner Control Center Field Test Final Report found that many Transmission Owners struggled with how to interpret the Control Center definition and that there was a lack of a common understanding of the term "control" versus "authority" as it relates to Transmission Operators.[29] While the current Control Center definition does not specifically identify Transmission Owners, the drafting team determined that a Transmission Owner may have a Control Center through its capability to control transmission Facilities.

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25 *Notice of Withdrawal of the North American Electric Reliability Corporation for Proposed Reliability Standard CIP-002-6*, Docket RM20-17-000 (February 5, 2021).

26 *Id.* at pp. 1-2.

27 The instant filing only addresses the portion of the 2016-02 SAR that was assigned to Project 2021-03 by the Standards Committee. Project 2021-03 has been tasked with addressing a number of additional SARs, which are not the subject of this filing. Project 2021-03 will remain ongoing and will address the additional SARs in subsequent filings.

28 NERC Project 2021-03 CIP-002 Transmission Owner Control Center Field Test Final Report (January 2023) [hereinafter Field Test Report]; https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

29 *Id.* at p. 7.

In its assessment of Attachment 1 of CIP-002-5.1a, the drafting team found that there was a lack of a common understanding of the phrase "perform the functional obligations of the [Transmission Operator]" as stated in Attachment 1 of CIP-002-5.1a.[30] The drafting team also concluded that there are entities for which the CIP-002-5.1a Attachment 1, Criterion 2.12 constraints associated with medium impact rating categorization are not commensurate with the risk posed to the BES should their Control Center be compromised or unavailable. Based on the field test results, the drafting team recommended modifications to the language of Criterion 2.12 to incorporate additional inclusion characteristics and exclusion criteria, recognizing that some Control Centers whose aggregate weighted value of lines exceeding 6000 may have a negligible impact on the reliability of the BES, if compromised.[31]

E. Virtualization Revisions Set forth in Proposed Reliability Standard CIP-002-7

NERC serves as the ERO in multiple jurisdictions, each with its own process for recognizing Reliability Standards. To ensure efficient development of standards, it is NERC's general practice that drafting teams revise the version of a Reliability Standard that has most recently been adopted by the NERC Board of Trustees. For this reason, the Project 2021-03 drafting team layered its revisions on top of the virtualization revisions set forth in proposed Reliability Standard CIP-002-7. Although adopted by the NERC Board of Trustees, CIP-002-7 remains pending before the Commission for approval.[32] The changes that are proposed in CIP-002-7 are incorporated into CIP-002-8.[33] A detailed discussion of Project 2016-02 and the pending

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30 *Id.* at p. 7.

31 *Id.* at p. iii.

32 *See Petition of the N. Am. Elec. Reliability Corp. for Approval of Critical Infrastructure Protection Reliability Standards*, Docket No. RM24-8-000 (July 10, 2024).

33 Exhibit A-2 provides a redline of all of the changes to CIP-002 from currently FERC-approved CIP-002-5.1a to the currently proposed CIP-002-8 and is inclusive of the changes proposed in CIP-002-7. (As noted above CIP-002-6 was withdrawn in 2022 and never went into effect.) Exhibit A-3 shows in redline the changes from the most recent NERC Board of Trustees approved version, CIP-002-7, to the proposed CIP-002-8 revisions, discussed herein.

revisions to proposed Reliability Standard CIP-002-7 may be found in the petition in FERC Docket No. RM24-8-000.[34]

IV. JUSTIFICATION FOR APPROVAL

As discussed in detail below, the revisions proposed by Project 2021-03 would advance reliability by revising both the Control Center definition and Criterion 2.12 of Attachment 1. The proposed revisions to the Control Center definition would ensure that Transmission Owners correctly identify their Control Centers and address the categorization of Transmission Owner Control Centers that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition ("SCADA").

The proposed revisions to Attachment 1 would clarify the "bright-line" criteria for Transmission Owners and Transmission Operators to categorize their BES Cyber Systems based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the BES.[35] The proposed revisions to Criterion 2.12 of Attachment 1 address the categorization of Transmission Owner Control Centers with the capability to control transmission Facilities. In addition, the proposed revisions would clarify the "perform the functional obligations of" language throughout Attachment 1 by instead referring to the reliability tasks performed by those same Registered Entities or, in the case of the Transmission Operator and the Transmission Owner, reference to the Control Center definition with respect to "reliability tasks" or "capability to control transmission Facilities", as appropriate.

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[34] *See Petition of the N. Amer. Elec. Reliability Corp. for Approval of Critical Infrastructure Protection Reliability Standards*, Docket No. RM24-8-000 (July 10, 2024).

[35] Exhibit D, Technical Rationale at 1.

The Project 2021-03 drafting team has not proposed substantive changes to the title, purpose, applicability, or Requirements of Reliability Standard CIP-002. As discussed *supra*, the revisions made by the Project 2021-03 drafting team were layered on top of the current NERC Board of Trustees approved draft, proposed Reliability Standard CIP-002-7, which is pending before the Commission.[36] Information regarding the revisions that first appear in proposed Reliability Standard CIP-002-7 may be found in that petition in FERC Docket No. RM24-8-000.[37]

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

Below, NERC provides an overview of the proposed Reliability Standard and the proposed revisions to the Control Center Definition. Additional information may be found in the Technical Rationale for Proposed Reliability Standard CIP-002-8, included as **Exhibit D** to this petition, as well as the Complete Record of Development, included as **Exhibit E**.

A. Modifications to Definition of Control Center

NERC proposes a revised definition of the term Control Center for inclusion in the *Glossary of Terms used in NERC Reliability Standards*. The drafting team found during the field test that many Transmission Owners struggled with how to interpret the Control Center definition in CIP-002-5.1a because it does not specifically identify Transmission Owners,[38] even though a Transmission Owner may have a Control Center through its ability to monitor and control the BES

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[36] *See Petition of the N. Am. Elec. Reliability Corp. for Approval of Critical Infrastructure Protection Reliability Standards*, Docket No. RM24-8-000 (July 10, 2024).

[37] *See id.* Most of the proposed revisions in CIP-002-7 serve to align the standard with updates to the NERC Glossary. Additionally, the proposed revisions in CIP-002-7 clarified that each "discrete" shared BES Cyber System meets medium impact rating 2.1 in Attachment 1 to CIP-002-7.

[38] The NERC Glossary defines Transmission Owner as "The entity that owns and maintains transmission Facilities." NERC Glossary, *supra*.

in real-time to perform the reliability tasks of a Transmission Operator.[39] This confusion resulted from a lack of a common understanding of the term "control" versus "authority".[40]

To address the identified ambiguities, the drafting team proposed the following underlined modifications to the definition of Control Center:

> Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.
>
> OR
>
> One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

The drafting team did not propose modifications to the Control Center definition for the Reliability Coordinator, Balancing Authority, Transmission Operator, and Generator Operator functions upon determining that the definition was well understood for these Registered Entities.[41] Rather, the proposed revisions would expand the Control Center definition to incorporate Transmission Owners so that a Transmission Owner is considered to have a Control Center if it has the capability to control transmission Facilities at two or more locations using SCADA.[42]

The proposed language "capability to control transmission facilities… using SCADA" differentiates between the control and monitor functions. For instance, a facility used by a Transmission Owner to monitor Facilities without any capability to electronically control those

[39] The NER Glossary defines Transmission Operator as "The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities." NERC Glossary, *supra*.

[40] *See* Exhibit D, Technical Rationale at 1; Field Test Report, *supra*, at 7.

[41] Exhibit D, Technical Rationale at 2.

[42] *Id.* at 2.

Facilities using a SCADA system would not fall within the Control Center definition.[43] By using the NERC-defined term "SCADA," the proposed definition excludes: (1) Cyber Assets used at a relay maintenance office to change relay settings, which may allow the capability to remotely operate a breaker; and (2) Cyber Assets and Human Machine Interface located at substations that have the capability to monitor and control transmission Facilities locally at the substation.[44] This ensures that entities appropriately focus on Control Centers at locations where, in the normal course of business, management of the BES occurs via a centralized system that consists of BES Cyber Systems and BES Cyber Assets. Since a SCADA system may include telemetry per the NERC defined term, the proposed Control Center definition specifically excludes field Cyber Assets used for telemetry from being part of the Control Center and associate impact level determination.[45] This ensures that field assets, including telemetry, continue to be classified based on their location and the associated impact level of that location. The proposed language "Facilities at two or more locations" recognizes that the Facilities will have separate street addresses and Facilities located at a single street address would be associated with a single location. An entity must have Facilities "at two or more locations" to meet this portion of the proposed definition.[46] This approach aligns with the existing Control Center definition language as it applies to the Transmission Operator and Generator Operator.

The proposed revised definition of Control Center as it applies to the Transmission Owner, would be tied to having a BES Cyber System or BES Cyber Asset, i.e., a SCADA system with the

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[43] *Id.* at 2.

[44] *Id.* at 2. While these Cyber Assets would not be considered a Control Center, they may be required to be protected under other cyber security categories.

[45] *Id.* at 2. The impact level of field Cyber Assets, including telemetry, should be evaluated based on the location and associated impact level contained in Attachment 1.

[46] *Id.* at 2-3.

capability to control. This would advance reliability by clarifying the facilities that are subject to the CIP requirements.[47]

B. Functional Obligations

The Field Test Report found that many Transmission Owners struggled with how to interpret the Control Center definition. Specifically, there was a "[l]ack of a common understanding of the term 'perform the functional obligations of the [Transmission Operator]'".[48] To address this finding, proposed Reliability Standard CIP-002-8 replaces the language throughout Attachment 1 that referred to the "functional obligations" of the different Registered Entities with references to the reliability tasks performed by those same Registered Entities or, in the case of the Transmission Operator and the Transmission Owner, reference to the Control Center definition with respect to "reliability tasks" or "capability to control transmission Facilities", as appropriate.[49] This proposed change eliminates confusion that the term "functional" is meant to invoke the NERC Functional Model, which is no longer actively maintained.[50] These proposed revisions also align with the proposed Control Center definition.[51]

Further, proposed Reliability Standard CIP-002-8 contains minor modifications, shown in redline in **Exhibit A**, which would revise language throughout Attachment 1 referring generally to Control Centers or backup Control Centers to use common language across all Responsible Entity types.

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47 *Id.* at 2.

48 Exhibit D, Technical Rationale at 1; Field Test Report, *supra*, at 7.

49 Exhibit D, Technical Rationale at 5.

50 The NERC Functional Model and NERC Functional Model Technical Document are historical documents that provided context and guidance to Drafting Teams during Reliability Standards development. As of October 2019, these documents are no longer being actively maintained. The criteria by which a Bulk-Power System user, owner, or operator must register with NERC, and therefore be subject to applicable NERC Reliability Standards, are described in the Organization Registration and Certification Manual and the Compliance Registry Criteria in Appendices 5A and 5B, respectively, of the FERC-approved NERC Rules of Procedure; available at: https://www.nerc.com/pa/Stand/Pages/FunctionalModel.aspx.

51 Exhibit D, Technical Rationale at 5.

C. Modifications to Criterion 2.12 of Attachment 1

Withdrawn Reliability Standard CIP-002-6 proposed revisions to Criterion 2.12 that would have applied to "[e]ach Control Center or backup Control Center, not included in the high impact rating, used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines with an 'aggregated weighted value' exceeding 6000 . . . ." The threshold of 6,000 was based on doubling the aggregate weighted value of 3,000 established in Criterion 2.5 of CIP-002-5.1a. This was intended to ensure that BES Cyber Systems that monitor and control BES Transmission Lines equivalent to two stations with medium impact BES Cyber Systems will be designated as medium impact, subject to any exclusions.[52]

Based upon the results of the field test, the drafting team confirmed that the previously proposed bright line of 6,000 remains an appropriate initial criterion to differentiate between low impact and medium impact BES Cyber Systems, when paired with appropriate inclusion and exclusion criteria. As a result, the drafting team determined that it would be appropriate to incorporate additional inclusion characteristics into revised Criterion 2.12, similar to the existing approach used in Criterion 2.5. The drafting team further concluded that it may be appropriate to incorporate exclusion criteria, recognizing that some Control Centers whose aggregate weighted value of lines exceeds 6,000 may have a negligible impact on the reliability of the BES based on specific observations during the field test.[53]

Proposed CIP-002-8 Attachment 1 includes criteria characterizing the level of impact of the BES Cyber Systems used by and located at certain assets for high impact BES Cyber Systems and associated with certain assets for medium and low impact BES Cyber Systems. Attachment 1

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[52] *See* Field Test Report, *supra*, at 6.

[53] *Id.* at 6.

Section 2 contains the medium impact criteria. Within this section, Criterion 2.12 of Attachment 1 addresses how BES Cyber Systems associated with Control Centers that perform the reliability tasks of the Transmission Operator and Transmission Owner are categorized.

As discussed in detail below, proposed Criterion 2.12 revises the "bright-line" criteria for Transmission Owners and Transmission Operators to categorize their BES Cyber Systems based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the BES. The modifications to proposed Criterion 2.12 of Attachment 1 are shown in blackline below:

> **2.12.** For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per BES Transmission Line," shown in the table below, for lines that are monitored and controlled by the Control Center or backup Control Center. Include each BES Transmission Line that is connected between two or more Transmission stations or substations.~~ used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H) above.~~

Voltage Value of a BES Transmission Line	**Weight Value per BES Transmission Line**
< 100 kV	**100**
100 kV to 199 kV	**250**
200 kV to 299 kV	**700**
300 kV to 499 kV	**1300**
500 kV and above	**0 (N/A)**

> Exclusion:
>
> Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may exclude the BES Transmission Lines that are contained in a single group of contiguous Elements from their "aggregate weighted value" calculation, where a group of contiguous Elements is defined as:

- a group of contiguous Elements emanating from multiple points of connection at 69 kV or higher;

- that are operated at less than 300 kV; and

- where the gross export does not exceed 75 MWh during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

Each of these elements are discussed below.

1. Aggregate Weighted Value

To assess the appropriate impact level of the BES Cyber Systems associated with a Control Center, proposed Criterion 2.12 assigns a weight value to the Transmission Lines that a Control Center monitors and controls, as portrayed in the table included in the proposed revisions to Criterion 2.12. The total aggregate weighted value would be used to account for the impact on the BES.

As revised, proposed Criterion 2.12 uses a total aggregate weighted value of 6,000, which was derived based on an entity with no single station or substation that meets Criterion 2.5, but has the capability or authority to control BES Transmission Lines with the equivalent weight of two stations or substations whose BES Cyber Systems would be classified as medium impact per Criterion 2.5.[54] This was derived from the "two or more locations" criterion documented in the proposed Control Center definition.[55] Following analysis of field test data, the drafting team determined that the 6,000 aggregate weighted value threshold defined in Criterion 2.12 would provide sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that are operated by a Transmission Operator or owned by a Transmission Owner.

[54] Technical Rationale at 6.
[55] *Id.* at 6.

This finding validated the earlier findings by the Project 2016-02 drafting team that drafted proposed Reliability Standard CIP-002-6,[56] which was withdrawn to allow for further study.[57]

For consistency with the existing Attachment 1 criteria, the weighted values for the various voltage classes of BES Transmission Lines were selected to align with the existing approved values in Criterion 2.5. For BES Transmission Lines 200 kV to 299 kV and for BES Transmission Lines 300 kV to 499 kV, the proposed weighted values per line would be 700 and 1300, respectively. Similar average MVA line loadings based on kV rating were calculated for BES Transmission Lines less than 100 kV and for BES Transmission Lines 100 kV to 199 kV using Appendix A of NERC's Severity Risk Index Enhancements Report which result in proposed weighted values of 100 and 250, respectively.[58] BES Transmission Lines that are energized at voltages of 500 kV and above would have no contribution to the aggregate weighted value given that Criterion 2.4 already includes BES Cyber Systems for any transmission Facilities at substations that are operated at 500 kV or higher as medium impact.[59]

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[56] *Petition of NERC for Approval of Proposed Reliability Standard CIP-002-6*, Docket No. RM20-17-000, at p. 13 (June 12, 2020).

[57] *Notice of Withdrawal of the North American Electric Reliability Corporation for Proposed Reliability Standard CIP-002-6*, Docket RM20-17-000, at p. 2 (Feb. 5, 2021). During the development of CIP-002-6, the drafting team considered similar language to what is proposed in the instant petition for Criterion 2.12 including the aggregate weighted value of 6,000. During development, NERC performed an analysis of Transmission Owners and Transmission Operators affected by an aggregate weighted value of less than and near 6,000. Seven entities total were selected from the Eastern, Western, and Texas Interconnections. The analysis simulated a compromised Control Center by simultaneously opening all Transmission lines owned by their respective Transmission Owner or Transmission Operator and monitored electrically adjacent BES elements for adverse reliability impacts associated with thermal overloads. This was a Steady-State analysis that locked generator, transformer taps, and switchable shunt devices to ensure more immediate potential impacts to the BPS could be monitored. In all cases studied, nearby areas showed voltage and frequency in oversupply due to the net loss of load compared to generation in the affected area. Oversupply system conditions are more easily remedied by backing down neighboring generation as opposed to ramping up generation or shedding load from undersupply system conditions. Based on the dataset used, the analysis found the following: (1) no low voltage issues; (2) High voltage issues could be remedied in Operations through backing down of generation whereby ramp down times are minimal in all situations; and (3) screen indicated no issues with thermal overloads of nearby buses and would not trigger adjacent protection systems. Based on these results, NERC determined that the proposed criterion was commensurate with the risk posed by the assets. *See Petition of NERC for Approval of Proposed Reliability Standard CIP-002-6*, Docket No. RM20-17-000, at p. 13.

[58] Exhibit D, Technical Rationale at 6.

[59] *Id.* at 6.

2. Exclusion Clause

In the Field Test Report, the drafting team concluded that it may be appropriate to incorporate specific exclusion criteria into proposed Criterion 2.12, recognizing that some Control Centers whose aggregate weighted value of lines exceeds 6,000 may have a negligible impact on the reliability of the BES if BES Cyber Systems were compromised.[60] Proposed Criterion 2.12 contains an exclusion clause that would allow Responsible Entities to appropriately categorize their BES Cyber Systems at Control Centers at a level that is commensurate with the associated risk for local systems having limited flow-through or generation export, and are primarily designed to serve load.[61] The proposed exclusion clause would apply to Transmission Operators and Transmission Owners where the initial calculated aggregate weighted value is less than 12,000. In such cases, the Transmission Operator/Transmission Owner would be able to calculate a revised aggregate weighted value that excludes those BES Transmission Lines that are contained in a single group of contiguous Elements operated at or greater than 69 kV but less than 300 kV, as defined by the Responsible Entity. The hourly integrated gross export from the group of contiguous Elements would not be allowed to exceed 75 MWh during the preceding 12 calendar months during non-Energy Emergency Alert conditions. Gross exports from the group of contiguous Elements during an Energy Emergency Alert condition that exceed 75 MWh would be allowed to enable the Responsible Entity to provide support to neighboring entities during Energy Emergency Alert conditions without any compliance impact.[62]

Entities that choose to pursue an exclusion under Criterion 2.12 would be responsible for documenting the process for calculating the hourly integrated gross export from the defined group

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60 Field Test Report, *supra*, at 6.
61 Exhibit D, Technical Rationale at 8.
62 *Id.* at 8.

of contiguous Elements. The concept of an hourly integrated value would avoid requiring entities to use an instantaneous value.[63]

Under the proposed revisions, limiting entities eligible to pursue an exclusion to those with an initial calculated aggregate weighted value of 12,000 would avoid inappropriate application of the exclusion to large control areas.[64] The aggregate weighted value of 12,000 would correspond to an entity with no single station or substation that meets Criterion 2.5 that has the capability or authority to control BES Transmission Lines with the equivalent weight of four stations or substations whose BES Cyber Systems would be classified as medium impact per Criterion 2.5.[65] During the field test performed by the drafting team, entities with an aggregate weighted value between 500 and 11,300 were evaluated and no reliability risks to the BES were identified for any entities.[66]

The proposed bright-line of 75 MWh would align with pre-existing criteria including the registration criteria for a Distribution Provider, and the registration criteria for a Generation Owner. Establishing a threshold would differentiate between non-impactful load serving areas and areas that are more likely to have an impact on the interconnected BES.[67] The proposed bright-line was selected to be conservative and would be below other established thresholds, such as the reporting requirement for uncontrolled loss of firm load resulting from a BES Emergency and firm load shedding resulting from a BES Emergency as documented in EOP-004. Energy Emergency Alert conditions were specifically excluded to ensure that a Responsible Entity would not be

63 *Id.* at 8.
64 *Id.* at 9.
65 *Id.* at 9.
66 *Id.* at 9.
67 *Id.* at 9.

disincentivized from providing all available assistance during emergency conditions due to future compliance considerations.[68]

As proposed, the exclusion clause would require an entity to measure gross export from their defined group of contiguous Elements. This would account for both generation output and flow-through the group of contiguous Elements. It would also ensure that an entity is unable to define a group of contiguous Elements that contains significant generation that supports the BES or with significant flow-through that impacts the BES.[69]

V. ENFORCEABILITY

The proposed Reliability Standard also includes measures that support each requirement by clearly identifying what is required and how the ERO will enforce the requirement. These measures help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[70] Additionally, the proposed Reliability Standard includes VRFs and VSLs. The VRFs and VSLs provide guidance on the way that NERC will enforce the requirements of the proposed Reliability Standard. The VRFs and VSLs for the proposed Reliability Standard comport with NERC and Commission guidelines related to their assignment. The VRFs and VSLs remain unchanged from those contained in proposed Reliability Standard CIP-002-7,[71] which is pending FERC approval. The VRFs and VSLs are located in **Exhibit A**.

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68 *Id.* at 9.
69 *Id.* at 9.
70 Order No. 672, *supra*, at P 327.
71 *See Petition of the N. Am. Elec. Reliability Corp. for Approval of Critical Infrastructure Protection Reliability Standards*, Docket No. RM24-8-000 (July 10, 2024).

VI. EFFECTIVE DATE

NERC respectfully requests that the Commission approve the proposed Reliability Standard to become effective as set forth in the proposed Implementation Plan, provided in **Exhibit B** hereto. The proposed Implementation Plan provides that proposed Reliability Standard CIP-002-8 and the proposed definition for Control Center shall become effective on the later of: (1) the effective date of CIP-002-7; or (2) the first day of the first calendar quarter that is three calendar months after the effective date of the Commission's order approving proposed Reliability Standard CIP-002-8.

Responsible Entities must comply with the periodic requirements in CIP-002-8. Requirement R2 within fifteen (15) calendar months of their last performance of Requirement R2 under the version of CIP-002 immediately effective prior to CIP-002-8. If revisions to Criterion 2.12 of Attachment 1 result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as a higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP-002-8. This would be considered a planned change, such that the Responsible Entity is expected to comply with the higher categorization 24 months after the effective date of CIP-002-8, as opposed to further extensions that would be allowable for an unplanned change. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a or CIP-002-7, Requirement 1, Part 1.3, whichever version of CIP-002 is enforceable immediately prior to the effective date of CIP-002-8.

The implementation period is designed to balance the urgency to implement the requirements while affording Responsible Entities time to incorporate the updated requirements into their processes. For these reasons, the proposed Implementation Plan for Reliability Standard

CIP-002-8 appropriately balances the urgency in the need to implement the standard against the time needed to comply.[72] NERC respectfully requests approval of the proposed Implementation Plan as submitted.

VII. CONCLUSION

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

- proposed Reliability Standard CIP-002-8, and associated elements included in Exhibit A;
- the proposed Implementation Plan included in Exhibit B; and
- the retirement of Reliability Standard CIP-002-7.

Respectfully submitted,

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Date: December 20, 2024

[72] *See* Order No. 672, *supra*, at P 333 (stating "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.").

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A

The Proposed Reliability Standard

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit A-1

CIP-002-8 Clean

Standard Development Timeline

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

Description of Current Draft

This is the final draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023
45-day formal comment period with additional ballot	April 2 – May 16, 2024
45-day formal comment period with additional ballot	August 29 – October 15, 2024

Anticipated Actions	Date
Final ballot	November 13 – 22, 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):

Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-8

3. **Purpose:** To identify and categorize BES Cyber Systems (BCS) and their associated BES Cyber Assets (BCA) for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BCS could have on the reliable operation of the Bulk Electric System (BES). Identification and categorization of BCS support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-8:

4.2.3.1. Cyber Systems at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Systems associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3. Cyber Systems, associated with communication networks and data communication links, between the Cyber Systems providing confidentiality and integrity of an ESP that extends to one or more geographic locations.

4.2.3.4. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.5. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. **Effective Dates:** See Implementation Plan for CIP-002

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts 1.1 through 1.3: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** RAS that support the reliable operation of the BES; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BCS according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BCS according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BCS according to Attachment 1, Section 3, if any (a discrete list of low impact BCS is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1.

R2. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program:
"Compliance Monitoring and 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 (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer identified BCS have not been categorized	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent, but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent, but less than or equal to 10 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category;	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent, but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high or medium impact BCS, more than 10 percent, but less than or equal to 15 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category;	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact

R #	Violation Severity Levels (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer high or medium BCS have not been identified.	OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than five, but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent, but less than or equal to 10 percent high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than five, but less than or equal to 10 high or medium BCS have not been identified.	OR For Responsible Entities with a total of 100 or fewer high or medium impact BCS, more than 10, but less than or equal to 15 identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 10 percent, but less than or equal to 15 percent high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than 10, but less than or equal to 15 high or medium BCS have not been identified.	BCS, more than 15 identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of high or medium impact BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BCS have not been identified.
R2	The Responsible Entity did not complete its review and update for the identification required for Requirement R1	The Responsible Entity did not complete its review and update for the identification required for Requirement R1	The Responsible Entity did not complete its review and update for the identification required for Requirement R1	The Responsible Entity did not complete its review and update for the identification required for Requirement R1

R #	Violation Severity Levels (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	within 15 calendar months, but less than or equal to 16 calendar months of the previous review. (Part 2.1) OR The Responsible Entity did not complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months, but less than or equal to 16 calendar months of the previous approval. (Part 2.2)	within 16 calendar months, but less than or equal to 17 calendar months of the previous review. (Part2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months, but less than or equal to 17 calendar months of the previous approval. (Part 2.2)	within 17 calendar months, but less than or equal to 18 calendar months of the previous review. (Part 2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months, but less than or equal to 18 calendar months of the previous approval. (Part 2.2)	within 18 calendar months of the previous review. (Part 2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (Part 2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Implementation Plan for Project 2021-03
- CIP-002-8 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	5/14/2020	Adopted by the NERC Board of Trustees.	Modified Criterion 2.12.
7	TBD	Virtualization Modifications	

Version	Date	Action	Change Tracking
7	5/9/2024	Adopted by the NERC Board of Trustees.	
8	TBD	Transmission Owners Control Centers Update	

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High impact rating

Each BCS used by and located at any of the following:

1.1. For Reliability Coordinators, each Control Center or backup Control Center used to perform the reliability tasks of the Reliability Coordinator.

1.2. For Balancing Authorities, each Control Center or backup Control Center used to perform the reliability tasks of the Balancing Authority for: 1) generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. For Transmission Operators and Transmission Owners, each Control Center or backup Control Center for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 For Generator Operators, each Control Center or backup Control Center used to perform the reliability tasks of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium impact rating

Each BCS, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher

voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each RAS or automated switching System that operates BES Elements, that, if destroyed, degraded, misused, or otherwise rendered unavailable, would cause one or more IROLs violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing UVLS or UFLS under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. For Generator Operators, each Control Center or backup Control Center used to perform the reliability tasks of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. For Transmission Operators and Transmission Owners, each Control Center or backup Control Center with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value

per BES Transmission Line," shown in the table below, for lines that are monitored and controlled by the Control Center or backup Control Center. Include each BES Transmission Line that is connected between two or more Transmission stations or substations.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:
Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may exclude the BES Transmission Lines that are contained in a single group of contiguous Elements from their "aggregate weighted value" calculation, where a group of contiguous Elements is defined as:

- a group of contiguous Elements emanating from multiple points of connection at 69 kV or higher;
- that are operated at less than 300 kV; and
- where the gross export does not exceed 75 MWh during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

2.13. For Balancing Authorities, each Control Center or backup Control Center used to perform the reliability tasks of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low impact rating

BCS not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS that support the reliable operation of the BES.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

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Exhibit A-2

CIP-002-8 Redline to Last FERC Approved

Standard Development Timeline

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

Description of Current Draft

This is the final draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023
45-day formal comment period with additional ballot	April 2 – May 16, 2024
45-day formal comment period with additional ballot	August 29 – October 15, 2024

Anticipated Actions	Date
Final Ballot	November 13 – 22, 2024
Board adoption	December 2024

CIP-002-8 is the combination of Project 2021-03's changes in on top of Project 2016-02's changes for virtualization. The following key describes the origin of changes in CIP-002-8:

Redline Text	Project 2021-03 Draft 3 changes
Redline Text	Project 2016-02 changes (Version 7)

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):

Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-8~~5.1a~~

3. **Purpose:** To identify and categorize BES Cyber Systems (BCS) and their associated BES Cyber Assets (BCA) for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BCS~~BES Cyber Systems~~ could have on the reliable operation of the Bulk Electric System (BES).~~BES.~~ Identification and categorization of BCS~~BES Cyber Systems~~ support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

   4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

   4.1.1. Balancing Authority

   4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

   4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

   4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

   4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

   4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme (RAS) where the RAS~~Special Protection System or Remedial Action Scheme~~ is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

~~**4.1.5. Interchange Coordinator or Interchange Authority**~~

~~4.1.6.~~4.1.5. **Reliability Coordinator**

~~4.1.7.~~4.1.6. **Transmission Operator**

~~4.1.8.~~4.1.7. **Transmission Owner**

4.2. **Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS~~Each Special Protection System or Remedial Action Scheme where the Special Protection System or Remedial Action Scheme~~ is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-8~~5.1a~~:

4.2.3.1. Cyber Systems~~Assets~~ at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Systems~~Assets~~ associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESP).

4.2.3.3. Cyber Systems, associated with communication networks and data communication links, between the Cyber Systems providing confidentiality and integrity of an ESP that extends to one or more geographic locations.

~~**4.2.3.3.**~~**4.2.3.4.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

~~**4.2.3.4.**~~**4.2.3.5.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**5.**~~ **Effective Dates:** See Implementation Plan for CIP-002

~~1. **24 Months Minimum –** CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~**6. Background:**~~

~~This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.~~

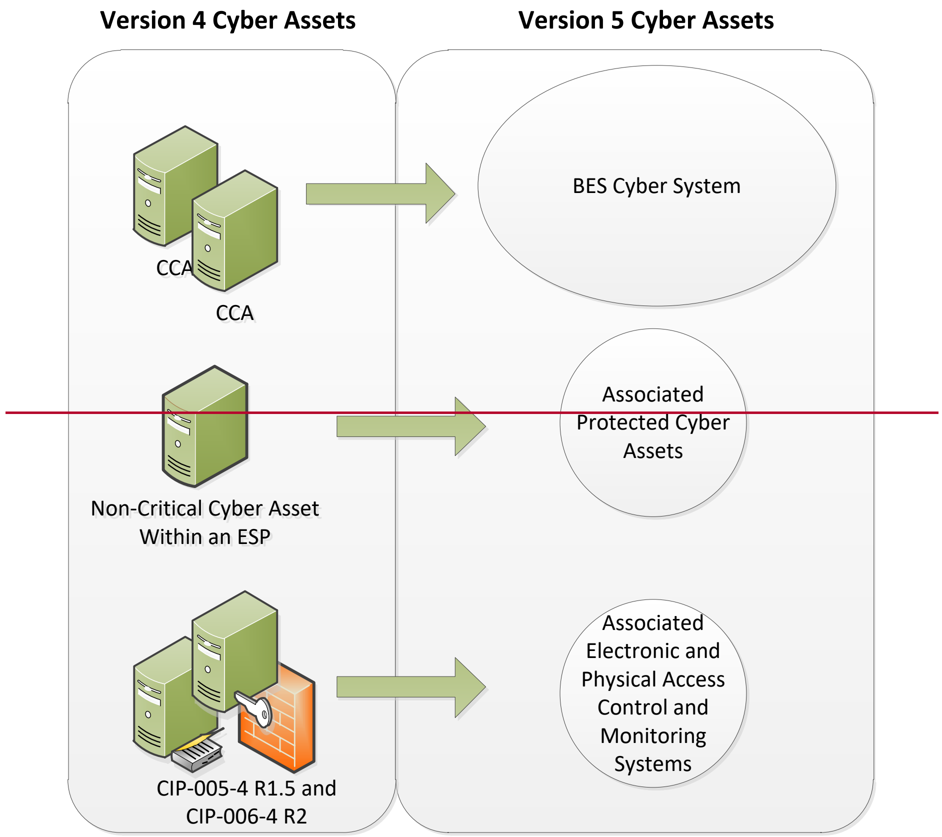
~~Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."~~

5. ~~Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS~~

~~tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~**BES Cyber Systems**~~

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

~~Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.~~

~~It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~Reliable Operation of the BES~~

~~The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.~~

~~Real-time Operations~~

~~One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.~~

~~Categorization Criteria~~

~~The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.~~

~~This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the~~

~~purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.~~

~~**Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems**~~

~~BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:~~

~~**Electronic Access Control or Monitoring Systems ("EACMS")** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.~~

~~**Physical Access Control Systems ("PACS")** – Examples include: authentication servers, card systems, and badge control systems.~~

~~**Protected Cyber Assets ("PCA")** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.~~

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts~~parts~~ 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

i. Control Centers and backup Control Centers;

ii. Transmission stations and substations;

iii. Generation resources;

iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;

v. RAS~~Special Protection Systems~~ that support the reliable operation of the BES~~Bulk Electric System~~; and

vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BCS~~BES Cyber Systems~~ according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BCS~~BES Cyber Systems~~ according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BCS~~BES Cyber System~~ according to Attachment 1, Section 3, if any (a discrete list of low impact BCS~~BES Cyber Systems~~ is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1~~, and Parts 1.1 and 1.2~~.

R2. Each~~The~~ Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. **Compliance Monitoring Process:**

   1.1. **Compliance Enforcement Authority:**
   "~~The Regional Entity shall serve as the~~ Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards. ~~("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

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

   - Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
   - If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
   - The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

   1.3. **Compliance Monitoring and Enforcement Program~~Assessment Processes~~:**
   "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

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

~~1.4. Additional Compliance Information~~

- ~~None~~

~~2. Table of Compliance Elements~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-~~85.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Operations Planning~~	~~High~~	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, five	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-8~~5.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			percent or fewer of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, five or fewer identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, five	For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than five percent but less than or equal to 10 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~and BES Cyber Systems~~, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly	For Responsible Entities with more than a total of 100 high or medium impact BCS~~BES Cyber Systems~~, more than 10 percent but less than or equal to 15 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact BCS~~and BES Cyber Assets~~, more than 10 but less than or equal to 15 identified BCS~~BES Cyber Assets~~ have not been categorized or have been incorrectly	BCS~~BES Cyber Systems~~, more than 15 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than 15 identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-8~~5.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			percent or fewer high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, five or fewer high or medium BCS~~BES Cyber Systems~~ have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than five percent but less than or equal to 10 percent high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than five but less than or equal to 10 high or medium BCS~~BES Cyber Systems~~ have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than 10 percent but less than or equal to 15 percent high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than 10 but less than or equal to 15 high or medium BCS~~BES Cyber Systems~~ have not been identified.	and medium impact BCS~~BES Cyber Systems~~, more than 15 percent of high or medium impact BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BCS~~BES Cyber Systems~~ have not been identified.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-8~~5.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	~~Operations Planning~~	~~Lower~~	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (Part 2~~R2~~.1) OR The Responsible Entity did not complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (Part 2~~R2~~.2)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (Part2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (Part 2~~R2~~.2)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (Part 2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (Part 2~~R2~~.2)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 18 calendar months of the previous review. (Part 2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (Part 2~~R2~~.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Implementation Plan for Project 2021-03

~~None.~~

- CIP-002-8 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	5/14/2020	Adopted by the NERC Board of Trustees.	Modified Criterion 2.12.
7	TBD	Virtualization Modifications	

Version	Date	Action	Change Tracking
7	5/9/2024	Adopted by the NERC Board of Trustees.	
8	TBD	-Transmission Owners Control Centers Update	

~~5.1a –~~Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High impact rating~~Impact Rating (H)~~

Each BCS~~BES Cyber System~~ used by and located at any of the following:

1.1. For Reliability Coordinators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Reliability Coordinator.

1.2. For Balancing Authorities, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center ~~used to perform the functional obligations of the Transmission Operator~~ for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 For Generator Operators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium impact rating~~Impact Rating (M)~~

Each BCS~~BES Cyber System~~, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BCS~~BES Cyber Systems~~ that meet this criterion are each discrete~~those~~ shared BCS~~BES Cyber Systems~~ that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BCS~~BES Cyber Systems~~ that meet this criterion are each discrete~~those~~ shared BCS~~BES Cyber~~

~~Systems~~ that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each ~~Special Protection System (SPS), Remedial Action Scheme (~~RAS~~),~~ or automated switching System that operates BES Elements, that, if destroyed, degraded, misused, or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or

cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. For Generator Operators, e~~E~~ach Control Center or backup Control Center~~, not already included in High Impact Rating (H),~~ ~~above,~~ used to perform the reliability tasks~~functional obligations~~ of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per BES Transmission Line," shown in the table below, for lines that are monitored and controlled by the Control Center or backup Control Center. Include each BES Transmission Line that is connected between two or more Transmission stations or substations. ~~used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:

Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may exclude the BES Transmission Lines that are contained in a single group of contiguous Elements from their "aggregate weighted value" calculation, where a group of contiguous Elements is defined as:

- a group of contiguous Elements emanating from multiple points of connection at 69 kV or higher;
- that are operated at less than 300 kV; and

- where the gross export does not exceed 75 MWh during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

~~2.12.~~2.13. For Balancing Authorities, e~~E~~ach Control Center or backup Control Center~~, not already included in High Impact Rating (H) above,~~ used to perform the reliability tasks~~functional obligations~~ of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low impact rating~~Impact Rating (L)~~

BCS

~~BES Cyber Systems~~ not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS~~Special Protection Systems~~ that support the reliable operation of the Bulk Electric System.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

~~Guidelines and Technical Basis~~ (Project 2021-03 decided to highlight the title versus the entire section of the GTB. The GTB sections were removed by Project 2016-02.)

~~**Section 4 – Scope of Applicability of the CIP Cyber Security Standards**~~

~~Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.~~

~~Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.~~

~~Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.~~

~~For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.~~

~~**CIP-002-5.1a**~~

~~CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."~~

~~The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber~~

~~Systems that would be subject to CIP-002-5.1a. The concept includes a number of named BES reliability operating services. These named services include:~~

~~Dynamic Response to BES conditions~~
~~Balancing Load and Generation~~
~~Controlling Frequency (Real Power)~~
~~Controlling Voltage (Reactive Power)~~
~~Managing Constraints~~
~~Monitoring & Control~~
~~Restoration of BES~~
~~Situational Awareness~~
~~Inter-Entity Real-Time Coordination and Communication~~

~~Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.~~

~~**Entity Registration**~~	~~**RC**~~	~~**BA**~~	~~**TOP**~~	~~**TO**~~	~~**DP**~~	~~**GOP**~~	~~**GO**~~
~~Dynamic Response~~		~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Balancing Load & Generation~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Controlling Frequency~~		~~X~~				~~X~~	~~X~~
~~Controlling Voltage~~			~~X~~	~~X~~	~~X~~		~~X~~
~~Managing Constraints~~	~~X~~		~~X~~			~~X~~	
~~Monitoring and Control~~			~~X~~			~~X~~	
~~Restoration~~			~~X~~			~~X~~	
~~Situation Awareness~~	~~X~~	~~X~~	~~X~~			~~X~~	
~~Inter-Entity coordination~~	~~X~~	~~X~~	~~X~~	~~X~~		~~X~~	~~X~~

~~**Dynamic Response**~~

~~The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:~~

- ~~Spinning reserves (contingency reserves)~~
  - ~~Providing actual reserve generation when called upon (GO,GOP)~~

- ~~Monitoring that reserves are sufficient (BA)~~
- ~~Governor Response~~
  - ~~Control system used to actuate governor response (GO)~~
- ~~Protection Systems (transmission & generation)~~
  - ~~Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)~~
  - ~~Zone protection for breaker failure (DP, TO, TOP)~~
  - ~~Breaker protection (DP, TO, TOP)~~
  - ~~Current, frequency, speed, phase (TO,TOP, GO,GOP)~~
- ~~Special Protection Systems or Remedial Action Schemes~~
  - ~~Sensors, relays, and breakers, possibly software (DP, TO, TOP)~~
- ~~Under and Over Frequency relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Under and Over Voltage relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Power System Stabilizers (GO)~~

~~Balancing Load and Generation~~

~~The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:~~

- ~~Calculation of Area Control Error (ACE)~~
  - ~~Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)~~
  - ~~Software used to perform calculation (BA)~~
- ~~Demand Response~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP,DP)~~
- ~~Manually Initiated Load shedding~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP, DP)~~
- ~~Non-spinning reserve (contingency reserve)~~
  - ~~Know generation status, capability, ramp rate, start time (GO, BA)~~
  - ~~Start units and provide energy (GOP)~~

~~**Controlling Frequency (Real Power)**~~

~~The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:~~

- ~~Generation Control (such as AGC)~~
  - ~~ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)~~
  - ~~Software to calculate unit adjustments (BA)~~
  - ~~Transmit adjustments to individual units (GOP)~~
  - ~~Unit controls implementing adjustments (GOP)~~
- ~~Regulation (regulating reserves)~~
  - ~~Frequency source, schedule (BA)~~
  - ~~Governor control system (GO)~~

~~**Controlling Voltage (Reactive Power)**~~

~~The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:~~

- ~~Automatic Voltage Regulation (AVR)~~
  - ~~Sensors, stator control system, feedback (GO)~~
- ~~Capacitive resources~~
  - ~~Status, control (manual or auto), feedback (TOP, TO,DP)~~
- ~~Inductive resources (transformer tap changer, or inductors)~~
  - ~~Status, control (manual or auto), feedback (TOP,TO,DP)~~
- ~~Static VAR Compensators (SVC)~~
  - ~~Status, computations, control (manual or auto), feedback (TOP, TO,DP)~~

~~**Managing Constraints**~~

~~Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:~~

- ~~Available Transfer Capability (ATC) (TOP)~~

- ~~Interchange schedules (TOP, RC)~~
- ~~Generation re-dispatch and unit commit (GOP)~~
- ~~Identify and monitor SOL's & IROL's (TOP, RC)~~
- ~~Identify and monitor Flow gates (TOP, RC)~~

~~Monitoring and Control~~

~~Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:~~

- ~~All methods of operating breakers and switches~~
    - ~~SCADA (TOP, GOP)~~
    - ~~Substation automation (TOP)~~

~~Restoration of BES~~

~~The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:~~

- ~~Restoration including planned cranking path~~
    - ~~Through black start units (TOP, GOP)~~
    - ~~Through tie lines (TOP, GOP)~~
- ~~Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)~~
- ~~Coordination (TOP, TO, BA, RC, DP, GO, GOP)~~

~~Situational Awareness~~

~~The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:~~

- ~~Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)~~
- ~~Change management (TOP,GOP,RC,BA)~~
- ~~Current Day and Next Day planning (TOP)~~
- ~~Contingency Analysis (RC)~~
- ~~Frequency monitoring (BA, RC)~~

~~Inter-Entity Coordination~~

~~The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:~~

- ~~Scheduled interchange (BA,TOP,GOP,RC)~~
- ~~Facility operational data and status (TO, TOP, GO, GOP, RC, BA)~~
- ~~Operational directives (TOP, RC, BA)~~

~~Applicability to Distribution Providers~~

~~It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.~~

~~Requirement R1:~~

~~Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.~~

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

~~Attachment 1~~

~~Overall Application~~

~~In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.~~

- ~~When the drafting team uses the term "Facilities", there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be~~

~~designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.~~

- ~~In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.~~
- ~~It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.~~

~~High Impact Rating (H)~~

~~This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.~~

~~The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.~~

~~Additional thresholds as specified in the criteria apply for this category.~~

~~Medium Impact Rating (M)~~

~~Generation~~

~~The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.~~

- ~~Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.~~

  ~~In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.~~

  ~~By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.~~

  ~~The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.~~

- ~~In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In~~

~~particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.~~

~~If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.~~

~~The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.~~

- ~~Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2,~~ ~~**Establish and Communicate System Operating Limits**~~~~, R5.1.1 and R5.1.3.~~

  ~~IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.~~

- ~~Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.~~

- ~~Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.~~

- ~~Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~**Transmission**~~

~~*The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.*~~

- ~~Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.~~

- ~~Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.~~

  ~~It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.~~

- ~~Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:~~

  - ~~Excluded radial facilities that would only provide support for single generation facilities.~~

  - ~~Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.~~

  ~~The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or~~

~~substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.~~

~~Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:~~

- ~~230 kV –> 700 MVA~~
- ~~345 kV –> 1,300 MVA~~
- ~~500 kV –> 2,000 MVA~~
- ~~765 kV –> 3,000 MVA~~

~~In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:~~

- ~~For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.~~

- ~~Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.~~

- ~~Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.~~

~~Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.~~

1. ~~The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations.~~

~~This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.~~

2. ~~The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.~~

~~The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.~~

- ~~Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2,~~ ~~**Establish and Communicate System Operating Limits**~~~~, R5.1.1 and R5.1.3.~~

- ~~Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.~~

- ~~Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.~~

- ~~Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.~~

- ~~Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems~~

~~and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.~~

~~This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~In ERCOT, the Load acting as a Resource ("LaaR") Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.~~

~~The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.~~

- ~~Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.~~
- ~~Criterion 2.13 categorizes as Medium Impact those BA Control Centers that "control" 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~Low Impact Rating (L)~~

~~BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.~~

~~Restoration Facilities~~

- ~~Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.~~

  ~~In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in~~

~~Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.~~

~~The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.~~

~~Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.~~

~~BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.~~

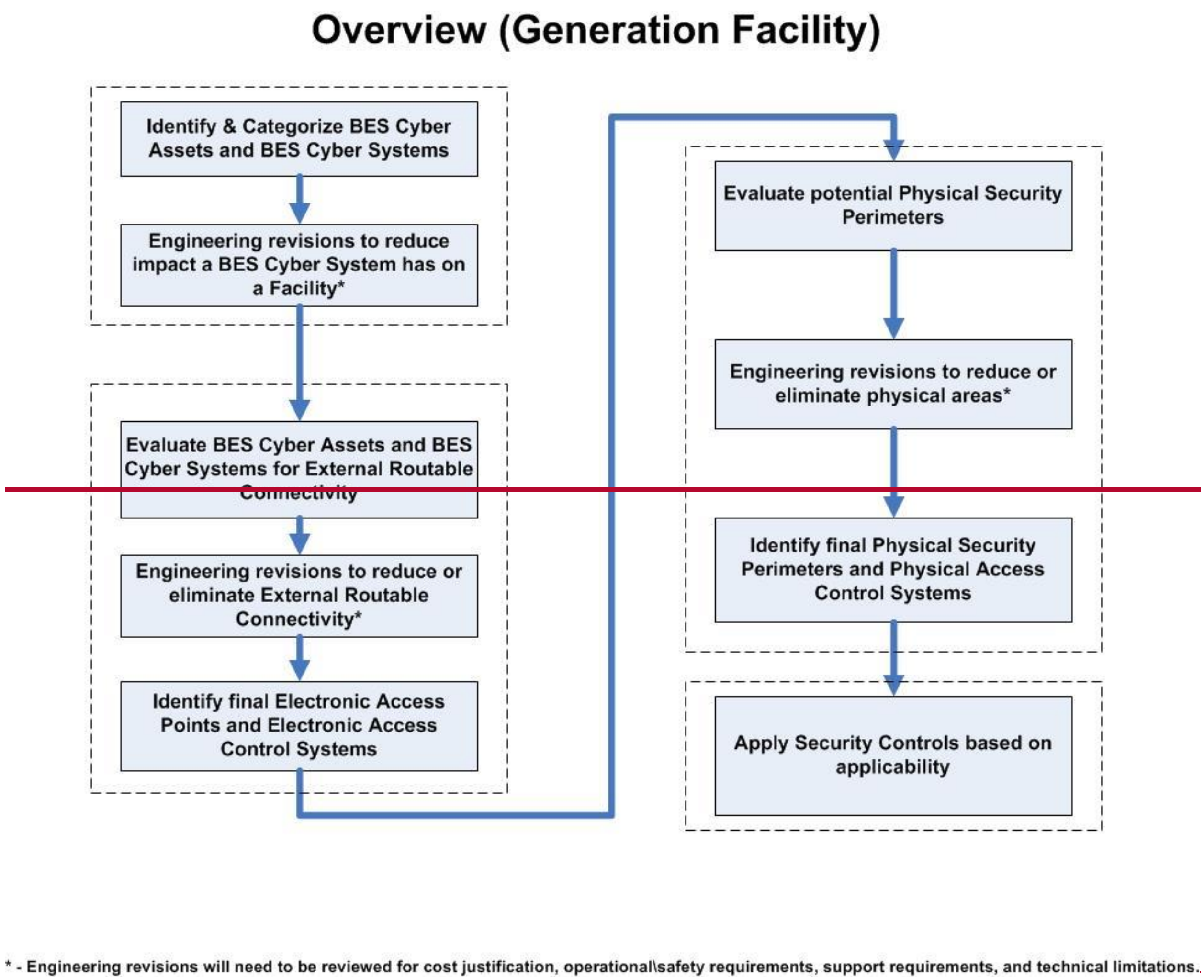
~~Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."~~

- ~~BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.~~

~~Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.~~

~~**Use Case: CIP Process Flow**~~

~~The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.~~



~~Rationale:~~

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

~~Rationale for R1:~~

~~BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of "bright-line" criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.~~

~~Rationale for R2:~~

~~The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager's approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.~~

~~5~~	~~11/26/12~~	~~Adopted by the NERC Board of Trustees.~~	~~Modified to coordinate with other CIP standards and to revise format to use RBS Template.~~
~~5.1~~	~~9/30/13~~	~~Replaced "Devices" with "Systems" in a definition in background section.~~	~~Errata~~
~~5.1~~	~~11/22/13~~	~~FERC Order issued approving CIP-002-5.1.~~	
~~5.1a~~	~~11/02/16~~	~~Adopted by the NERC Board of Trustees.~~	
~~5.1a~~	~~12/14/2016~~	~~FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.~~	

~~Appendix 1~~

~~Requirement Number and Text of Requirement~~
~~CIP-002-5.1, Requirement R1~~ ~~R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:~~ ~~i. Control Centers and backup Control Centers;~~ ~~ii. Transmission stations and substations;~~ ~~iii. Generation resources;~~ ~~iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;~~ ~~v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and~~ ~~vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.~~ ~~1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;~~ ~~1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and~~ ~~1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).~~ ~~Attachment 1, Criterion 2.1~~ ~~2. Medium Impact Rating (M)~~ ~~Each BES Cyber System, not included in Section 1 above, associated with any of the following:~~ ~~2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.~~
~~Questions~~
~~Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."~~ ~~The Interpretation Drafting Team identified the following questions in the RFI:~~

~~1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~

~~2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~

~~3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~

~~Responses~~

~~Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~

~~The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)~~

~~Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:~~

> ~~The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~

~~The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.~~

~~The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:~~

> ~~Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating~~

~~criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1:~~ ~~**Impact Rating of Generation Resource Shared BES Cyber Systems**~~ ~~for further information and examples.~~ ~~**Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?**~~ ~~The phrase applies to each discrete BES Cyber System.~~

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Exhibit A-3

CIP-002-8 Redline to last NERC Board of Trustees Approved

Standard Development Timeline

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

Description of Current Draft

This is the final draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023
45-day formal comment period with additional ballot	April 2 – May 16, 2024
45-day formal comment period with additional ballot	August 29 – October 15, 2024

Anticipated Actions	Date
Final Ballot	November 13 – 22, 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):

Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-8~~7~~

3. **Purpose:** To identify and categorize BES Cyber Systems (BCS) and their associated BES Cyber Assets (BCA) for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BCS could have on the reliable operation of the Bulk Electric System (BES). Identification and categorization of BCS support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-8~~7~~:

4.2.3.1. Cyber Systems at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Systems associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESP).

4.2.3.3. Cyber Systems, associated with communication networks and data communication links, between the Cyber Systems providing confidentiality and integrity of an ESP that extends to one or more geographic locations.

4.2.3.4. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.5. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See Implementation Plan for CIP-002

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** RAS that support the reliable operation of the BES; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BCS according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BCS according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BCS according to Attachment 1, Section 3, if any (a discrete list of low impact BCS is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1.

R2. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. **Compliance Monitoring Process:**

1.1. Compliance Enforcement Authority:

"~~The Regional Entity shall serve as the~~ Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards. ~~("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

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

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program~~Assessment Processes~~:

"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. ~~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 (CIP-002-8~~7~~)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer of identified BCS have not been categorized or have been incorrectly	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent but less than	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high or medium impact BCS, more than 10 percent but less than or	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of identified BCS have not been categorized or have been

R #	Violation Severity Levels (CIP-002-8~~7~~)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer	or equal to 10 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent but less than or equal to 10 percent high or medium BCS have not been identified;	equal to 15 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact BCS, more than 10 but less than or equal to 15 identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 10 percent but less than or equal to 15 percent high or medium BCS have not been identified;	incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than 15 identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of high or medium impact BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15

R #	Violation Severity Levels (CIP-002-8~~7~~)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	high or medium BCS have not been identified.	OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than five but less than or equal to 10 high or medium BCS have not been identified.	OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than 10 but less than or equal to 15 high or medium BCS have not been identified.	high or medium impact BCS have not been identified.
R2	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (Part 2.1) OR The Responsible Entity did not complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (Part2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (Part 2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 18 calendar months of the previous review. (Part 2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (Part 2.2)

R #	Violation Severity Levels (CIP-002-8~~7~~)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	months of the previous approval. (Part 2.2)	months of the previous approval. (Part 2.2)	months of the previous approval. (Part 2.2)	

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Implementation Plan for Project 2021-03
- CIP-002-8 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	5/14/2020	Adopted by the NERC Board of Trustees.	Modified Criterion 2.12.
7	TBD	Virtualization Modifications	

Version	Date	Action	Change Tracking
7	5/9/2024	Adopted by the NERC Board of Trustees.	
8	TBD	-Transmission Owners Control Centers Update	

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High impact rating

Each BCS used by and located at any of the following:

1.1. For Reliability Coordinators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Reliability Coordinator.

1.2. For Balancing Authorities, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center ~~used to perform the functional obligations of the Transmission Operator~~for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 For Generator Operators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

~~3.~~2. Medium impact rating

Each BCS, not included in Section 1 above, associated with any of the following:

~~3.1.~~2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

~~3.2.~~2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

~~3.3.~~2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

~~3.4.~~2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

~~3.5.~~2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

~~3.6.~~2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

~~3.7.~~2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

~~3.8.~~2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

~~3.9.~~2.9. Each RAS or automated switching System that operates BES Elements, that, if destroyed, degraded, misused, or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

~~3.10.~~2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding

(UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

~~3.11.~~2.11. For Generator Operators, e~~E~~ach Control Center or backup Control Center~~, not already included in High Impact Rating (H), above,~~ used to perform the reliability tasks~~functional obligations~~ of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per BES Transmission Line," shown in the table below, for lines that are monitored and controlled by the Control Center or backup Control Center. Include each BES Transmission Line that is connected between two or more Transmission stations or substations. ~~used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:

Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may exclude the BES Transmission Lines that are contained in a single group of contiguous Elements from their "aggregate weighted value" calculation, where a group of contiguous Elements is defined as:

- a group of contiguous Elements emanating from multiple points of connection at 69 kV or higher;
- that are operated at less than 300 kV; and
- where the gross export does not exceed 75 MWh during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

~~3.12.~~ 2.13. For Balancing Authorities, ~~E~~each Control Center or backup Control Center~~, not already included in High Impact Rating (H) above,~~ used to perform the reliability tasks~~functional obligations~~ of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

~~5.~~ 3. Low impact rating

BCS not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS that support the reliable operation of the Bulk Electric System.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

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Exhibit B

Implementation Plan

Implementation Plan

Project 2021-03 CIP-002 | Reliability Standard CIP-002-8

Applicable Standard(s)

- Reliability Standard CIP-002-8 – Cyber Security - BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-7 – Cyber Security - BES Cyber System Categorization

Prerequisite Definition

This definition must be approved before the Applicable Standard becomes effective:

- Cyber System[1]

Applicable Entities

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

Modified 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 Modified Definition

Control Center - One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator

[1] The new term Cyber System was developed as part of Project 2016-02 – Modifications to CIP Standards.

for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

Background

Project 2021-03 includes revisions to the Control Center definition and CIP-002 Attachment 1. The proposed revisions to the Control Center definition are intended to ensure Transmission Owners correctly identify their Control Centers. The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers that have the capability to control transmission Facilities at two or more locations in real-time using SCADA. These modifications resulted from recommendations from the CIP-002 Transmission Owner Control Center Field Test Report.[2]

General Considerations

This Implementation Plan includes phased-in implementation dates for CIP-002-8, Attachment 1. The phased-in implementation dates allow Responsible Entities[3] a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System.

Effective Date and Phased-In Compliance Dates

The effective date for proposed Reliability Standard CIP-002-8 and the modified definition is provided below. Where the drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (i.e., an entire Requirement or a portion of it), the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible 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 CIP-002-8 and Control Center Definition

Where approval by an applicable governmental authority is required, the standard and Control Center definition shall become effective on the later of 1) the effective date of CIP-002-7; or 2) the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving CIP-002-8, or as otherwise provided for by the applicable governmental authority.

[2] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf

[3] As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

Where approval by an applicable governmental authority is not required, the standard and Control Center definition shall become effective on the later of 1) the effective date of CIP-002-7; or 2) the first day of the first calendar quarter that is three (3) months after the date CIP-002-8 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Dates for CIP-002-8

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-8, Requirement R2 within 15 calendar months of their last performance of Requirement R2 under the version of CIP-002 immediately effective prior to CIP-002-8.

Phased-in Implementation Date for CIP-002-8, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criteria 2.12 of Attachment 1 to CIP-002-8 result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as that higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP- 002-8. This would be considered a planned change, such that the Responsible Entity is expected to comply with the higher categorization 24 months after the effective date of CIP-002-8 as opposed to further extensions that would be allowable for an unplanned change. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a or CIP-002-7, Requirement R1, Part 1.3, whichever version of CIP-002 is enforceable immediately prior to the effective date of CIP-002-8.

Planned or Unplanned Changes

Planned Changes

Planned changes refer to any changes of the electric system or a BES Cyber System which were planned and implemented by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-8, Requirement R2.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-8, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

For planned changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control or Monitoring Systems and Protected Cyber Assets, etc. For periodic requirements in Reliability Standards CIP-004 through CIP-011, the period within which Responsible Entities must initially comply begins on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control or Monitoring Systems and Protected Cyber Assets.

Unplanned Changes

Unplanned changes refer to any changes of the electric system or a BES Cyber System which were not planned by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-8, Requirement R2.

For example, consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-8, Attachment 1, then an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-8, Attachment 1, criteria.

For unplanned changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control or Monitoring Systems and Protected Cyber Assets, etc. For periodic requirements in Reliability Standards CIP-004 through CIP-011, the period within which Responsible Entities must initially comply begins at the end of the timelines listed below.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to Medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System	12 months
Responsible Entity identifies its first high impact or medium impact BES Cyber System (i.e., the Responsible Entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002 identification and categorization processes)	24 months

Retirement Date

Reliability Standard CIP-002-7

Reliability Standard CIP-002-7 shall be retired immediately prior to the effective date of Reliability Standard CIP-002-8 in the particular jurisdiction in which the revised standard is becoming effective.

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit C

Order No. 672 Criteria

EXHIBIT C

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

In Order No. 672,[1] the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. The discussion below identifies these factors and explains how proposed Reliability Standard CIP-002-8 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 Standard identifies and categorizes Bulk Electric System ("BES") Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems supports appropriate protection against compromises that could lead to misoperation or instability in the BES. Specifically, proposed Reliability Standard CIP-002-8 – Cyber Security – BES Cyber System Categorization would advance the reliability of

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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 id.* 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 id. 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.").

the Bulk-Power System ("BPS") by revising the "bright-line" criteria for applicable Transmission Owners and Transmission Operators to categorize their BES Cyber Systems based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the BES. The proposed changes would benefit reliability by: (1) modifying the Control Center definition to include certain Transmission Owners that have the ability to control transmission Facilities; (2) revising Attachment 1 to address the categorization of Transmission Owner Control Centers; and (3) revising Attachment 1 to replace the language "perform the functional obligations of" with a reference to "reliability tasks" as included in the Control Center definition or, in the case of the Transmission Operator or Transmission Owner, reference to the Control Center definition with respect to "reliability tasks" or "capability to control transmission Facilities", as appropriate. The proposed revisions in Reliability Standard CIP-002-8 are thus designed to achieve a specific reliability goal and contain a technically sound means to achieve that goal.

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

Proposed Reliability Standard CIP-002-8 is clear and unambiguous as to what is required and who is required to comply, in accordance with Order No. 672. The proposed standard is applicable to Balancing Authorities, Distribution Providers, Generator Operators, Generator Owners, Reliability Coordinators, Transmission Operators, and Transmission Owners. The

[3] *See id.* 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 id. 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.").

proposed standard clearly articulates the actions that applicable entities must take to comply with the standard.

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

The Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") for proposed Reliability Standard CIP-002-8 remain unchanged from the VRFs and VSLs proposed in Reliability Standard CIP-002-7, which is pending before the Commission in Docket No. RM24-8-000, and continue to comport with NERC and Commission guidelines related to their assignment. The assignment of the severity level for each VSL is consistent with the corresponding requirement, and the VSLs should ensure uniformity and consistency in the determination of penalties. The VSLs do not use any ambiguous terminology, thereby supporting uniformity and consistency in the determination of similar penalties for similar violations. For these reasons, the proposed 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 Standard contains measures that support the requirements by clearly identifying what is required to demonstrate compliance. These measures help provide clarity regarding the manner in which the requirements will be enforced and help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without

[4] *See id.* 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 id.* 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.").

prejudice to any party. The measures are substantively unchanged from CIP-002-7, which is pending before the Commission in Docket No. RM24-8-000.

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 Standard achieves the reliability goals effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard clearly articulates the security objective that applicable entities must meet while permitting entities to apply a risk-based approach to the categorization of BES Cyber Systems.

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]

Proposed Reliability Standard CIP-002-8 does not reflect a "lowest common denominator" approach. The proposed Reliability Standard helps to ensure that entities allocate resources commensurate with the adverse impact that loss, compromise, or misuse of BES Cyber Systems could have on the reliable operation of the BES.

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[6] *See id.* 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 id.* 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 id. 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.").

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 Standard would apply consistently throughout North America and does not favor one geographic area or regional model.

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

Proposed Reliability Standard CIP-002-8 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.

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

The proposed implementation period, included as **Exhibit B**, for the proposed Reliability Standard is just and reasonable and designed to balance the urgency to implement the requirements while affording Responsible Entities time to incorporate the updated requirements into their processes. The proposed implementation plan provides that proposed Reliability Standard CIP-

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[8] *See id.* 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.").

[9] *See id.* 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 id.* 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.").

002-8 and the proposed definition for Control Center shall become effective on the later of: (1) the effective date of CIP-002-7; or (2) the first day of the first calendar quarter that is three calendar months after the effective date of the Commission's order approving proposed Reliability Standard CIP-002-8.

This Implementation Plan includes phased-in implementation dates for CIP-002-8, Attachment 1. The phased-in implementation dates would allow Responsible Entities a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System. In addition, the proposed Implementation Plan carries forward the planned and unplanned changes section that has been used in implementation plans associated with previous versions of the CIP Reliability Standards, with certain conforming changes.

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

Proposed Reliability Standard CIP-002-8 was developed in accordance with NERC's Commission-approved processes for developing and approving Reliability Standards. **Exhibit E** includes a summary of the development proceedings for the proposed standard, and details the processes followed to develop the proposed standard. These processes included, among other things, public comment and ballot periods. Additionally, all meetings of the drafting team were properly noticed and open to the public.

[11] *See id.* 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 proposed standard. No comments were received that indicated that the proposed standard conflicts with other vital public interests.

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

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

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12 *See id.* 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 id.* 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.").

Exhibit D

Technical Rationale

Technical Rationale

Project 2021-03 CIP-002 | Reliability Standard CIP-002-8

CIP-002-8 – Cyber Security – BES Cyber System Categorization and Control Center Definition

Introduction

This document explains the technical rationale and justification for the proposed revisions to the Control Center Definition and Reliability Standard CIP-002-8. It provides stakeholders and the ERO Enterprise with a description of the technical requirements in the Reliability Standard. These are not Reliability Standards and should not be considered mandatory and enforceable.

Updates to this document include the Project 2021-03 CIP-002 Drafting Team's (DT's) intent in drafting changes to the requirements and definition.

Overview

Project 2021-03 proposes revisions to the Control Center definition and CIP-002-8 criterion 2.12 in Attachment 1. CIP-002-8 provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems (BCS) based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System (BES). The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers (TOCCs) performing the functional obligations of a Transmission Operator (TOP), specifically those that meet medium impact criteria, and clarifying the language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.

Rationale for Control Center Definition Modification

Rationale for Proposing Modifications to the Control Center Definition

During the CIP-002 TOCC Field Test[1], it was found that many Transmission Owners (TO)s struggled with how to interpret the Control Center definition. While the current Control Center definition does not specifically identify TOs, a TO may have a Control Center through its ability to monitor and control the BES in real-time to perform the reliability tasks of a TOP. This struggle surfaced in the following three manners:

- Lack of a common understanding of the term "control" versus "authority" as it relates to TOPs
- Lack of a common understanding of the term "perform the functional obligations of the TOP" as stated in Attachment 1 of CIP-002-5.1a.
- Lack of a common understanding of the term "associated data centers" versus TO BES Cyber Assets capable of controlling transmission Facilities.

Modifications to the definition have been proposed to eliminate ambiguity.

[1] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

Applicable Control Center Entities

Considering industry comments, the Control Center definition for Reliability Coordinator (RC), Balancing Authority (BA), TOP, and Generator Operator (GOP) was not revised. The industry felt the Control Center and data center definitions for these registered entities were well understood and is structured to explicitly identify the four different types of registered entities have gone through the scrutiny of compliance monitoring. Thus, no changes were made for these four registered entities that could have a Control Center.

The Control Center definition was expanded to incorporate the TO as follows: “One or more facilities of a TO that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers and excluding field Cyber Assets used for telemetry.”

A TO is considered to have a Control Center if it has the capability to control transmission Facilities at two or more locations using SCADA. The concept of ‘capability to control using SCADA’ is specifically used to differentiate between control and monitor functions – i.e., clarify that a facility used by a TO to monitor Facilities without any capability to electronically control those Facilities using a SCADA system does not fall within the Control Center definition. For example, a TO who issues verbal instructions to field switching personnel but who does not have the ‘capability to control using SCADA’ would not be considered to have a Control Center.

The use of the NERC defined term “SCADA” is intended to exclude Cyber Assets used at a relay maintenance office to change relays setting, which may allow the capability to remotely operate a breaker. These Cyber Assets would not be considered a Control Center but may be required to be protected under other cyber security categories. Likewise, the use of the NERC defined term “SCADA” is intended to exclude Cyber Assets and Human Machine Interface (HMI) located at substations that have the capability to monitor and control transmission Facilities locally at the substation. These Cyber Assets would not be considered a Control Center but may be required to be protected under other cyber security categories.

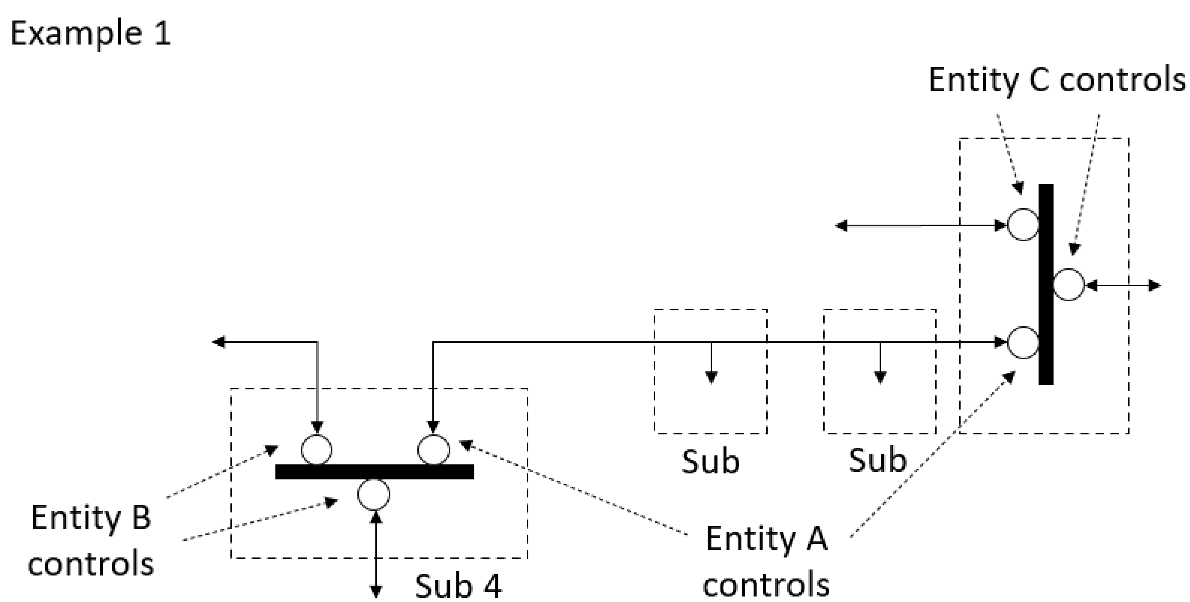
Because a SCADA system may include telemetry per the NERC defined term, the DT has crafted language to specifically exclude field Cyber Assets used for telemetry from being part of the Control Center and associated impact level determination. The impact level of field Cyber Assets, including telemetry, should be evaluated based on the location and associated impact level contained in Attachment 1.

The part of the Control Center definition that is applicable to the TO is not tied to the functional obligations of the TOP, nor is it tied to any TOP reliability tasks. Rather, it is tied to having a BES Cyber System or BES Cyber Asset, i.e., a SCADA system with the capability to control. It does not matter if the TO has a reliability task with pre-authorized authority from the TOP to control transmission Facilities or only receives operating instructions from the TOP. The cyber security risk that must be protected is access to the BES Cyber System or BES Cyber Asset(s), i.e., SCADA system that are able to control the transmission Facility.

When considering the language “transmission Facilities at two or more locations” and “generation Facilities at two or more locations,” it is generally expected that the Facilities will have separate street addresses. Facilities located at a single street address would be associated with a single location. An entity must have more than one Facility and must have Facilities at two or more locations in order to have “transmission Facilities at two or more locations” or “generation Facilities at two or more locations.”

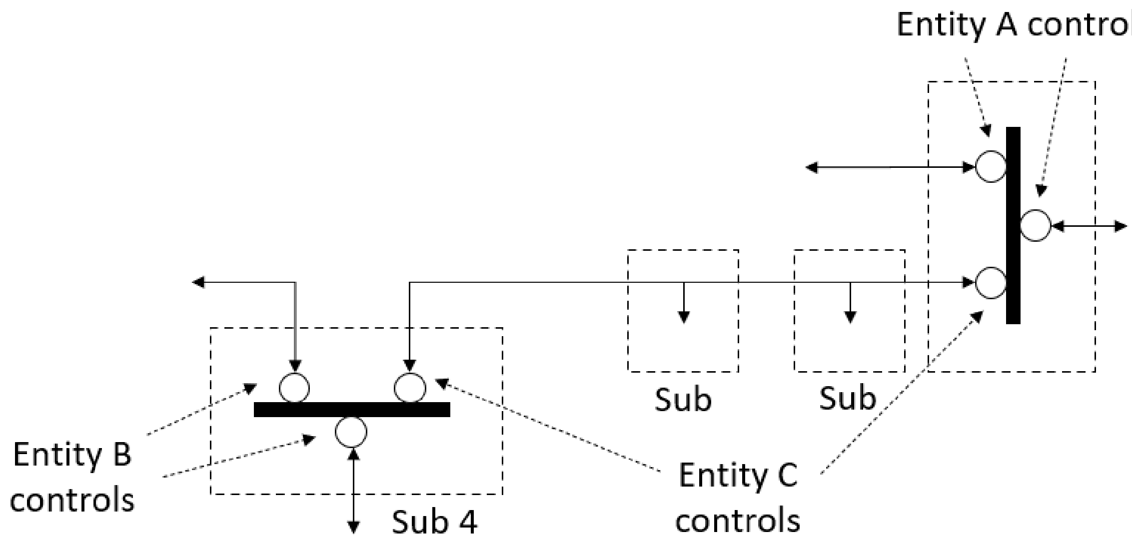
With respect to Transmission Owners who have facilities that are capable of controlling High Voltage Direct Current (HVDC) Facilities, each Responsible Entity will need to engage with their Regional Entity in order to determine how the language “transmission Facilities at two or more locations” should be applied based on the specific configuration. The current definition has not changed for Transmission Operators, and thus there is no expected change in applicability to classification of their operated HVDC Facilities.

The following examples differentiate between a single transmission Facility and two or more transmission Facilities at one location.

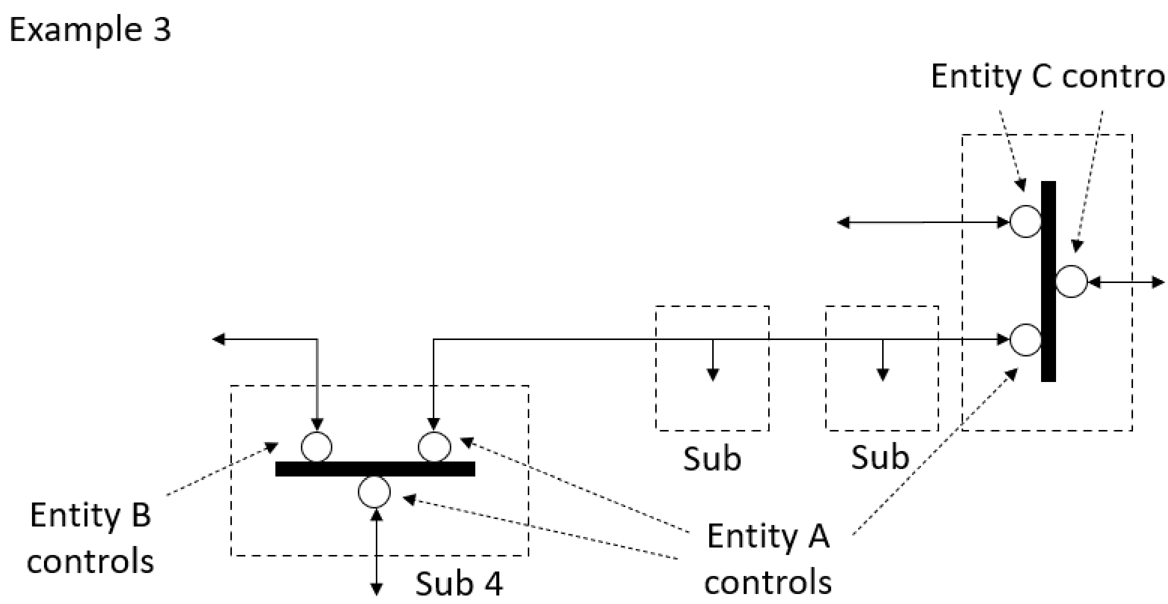


In Example 1, Entity A has control of breakers at both ends of a Transmission Line, which constitutes a transmission Facility. Because Entity A controls a single transmission Facility at 2 locations, Entity A does not meet the TO or TOP Control Center definition.

Example 2



In Example 2, Entity A has control of breakers at one end of two transmission Facilities, but at a single location. Because Entity A controls two transmission Facilities at only 1 location, Entity A does not meet the TO or TOP Control Center definition.



In Example 3, Entity A has control of breakers at one end of two transmission Facilities and a breaker at different location. Because Entity A controls two transmission Facilities at 2 locations, Entity A does meet the TO or TOP Control Center definition.

Associated Data Centers

The Control Center definition includes the phrase "associated data centers". This phrasing is intended to ensure that Cyber Assets that are not co-located in the facilities that host operating personnel are included in the Control Center definition, and are thus included in the process of identifying and categorizing BCS.

Industry comments received during the standard drafting process indicate that lack of a NERC definition for data center has not been an issue in applying the Control Center definition. Therefore, the term "associated data center" was retained in the revised definition.

Rationale for CIP-002-8 Attachment 1 Modifications

Removal of Functional Obligation Language

Language throughout Attachment 1 of CIP-002-8 that referred to the "functional obligations" of the different Registered Entities has been replaced with references to the reliability tasks performed by those same Registered Entities. This change was incorporated given that the NERC Functional Model is no longer being actively maintained and to align with the language used in the Control Center definition. It also resolves an issue whereby an entity may be identified as performing functional obligations even though that entity is not currently registered with NERC. The proposed modifications ensure that the responsibility for entity registration precedes enforcement of CIP-002-8. Usage of 'reliability task" is to provide flexibility to an entity when referring to activities performed by that entity to ensure resource adequacy and operational reliability of BES Elements and Facilities. Additional information on the BES reliability operating services that may be useful to entities when they are defining their reliability tasks can be found in the technical rationale document associated with CIP-002-7. Each entity is ultimately responsible for reviewing their obligations under the NERC Standards to identify their reliability tasks.

Calculating an Aggregate Weighted Value per Criteria 2.12

The total aggregate weighted value is used to account for the impact on the BES. The 6,000 aggregate weighted value threshold defined in criterion 2.12 provides sufficient differentiation for medium and low impact BCS associated with Control Centers that are operated by a registered TOP or owned by a registered TO. DT analysis of data obtained from the CIP-002 Transmission Owner Control Center Field Test[2] validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

The total aggregate weighted value of 6,000 was derived based on an entity with no single station or substation that meets criterion 2.5, but who has the capability or authority to control BES Transmission Lines with the equivalent weight of two stations or substations whose BCS would be classified as medium impact per criterion 2.5. This is ultimately derived from the "two or more locations" criteria that is documented in the Control Center definition.

For consistency with the existing Attachment 1 criteria, the weighted values for the various voltage classes of BES Transmission Lines were selected to align with the existing approved values in criterion 2.5. For BES Transmission Lines 200 kV to 299 kV and for BES Transmission Lines 300 kV to 499 kV, the weighted values per line are 700 and 1300, respectively. Similar average MVA line loadings based on kV rating were calculated for BES Transmission Lines less than 100 kV and for BES Transmission Lines 100 kV to 199 kV using Appendix A of NERC's Severity Risk Index Enhancements Report which result in weighted values of 100 and 250, respectively.

BES Transmission Lines that are energized at voltages of 500 kV and above have no contribution to the aggregated weighted value given that criterion 2.4 already includes BCS for any transmission Facilities at substations that are operated at 500 kV or higher as medium impact. Further, criterion 1.3 includes the BCS used by and located at Control Centers or backup Control Centers that monitor and control any BES Transmission Lines at substations that are operated at 500 kV or higher as high impact. During industry commenting periods, the drafting team received many inquiries into the use of zero (0) in the table for criterion 2.12, which was originally proposed to remain consistent with existing criteria 2.5. Pursuant to these comments, the DT elected to use "0 (N/A)" in both criterion 2.5 and criterion 2.12 to make it clear that these lines are not relevant for inclusion in the aggregate weighted value calculation.

For the purpose of identifying a Responsible Entity's BES Transmission Lines, a Transmission Line is typically defined by the Protection System(s) that would be used to isolate faults on the Transmission Line – which is generally defined by a boundary of fault interrupting devices (e.g., breakers) that are controlled by the line's Protection System(s). Transmission Lines can be single-ended, two-ended or three-ended.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages less than 100 kV, are monitored and controlled by a Control Center, and have been specifically designated as part of the BES via the

[2] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

NERC Rules of Procedure (ROP) Exception Process.

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV, connect to another Transmission station or substation, and are monitored and controlled by a Control Center. This includes BES Transmission Lines that connect to neighboring entities.
- Multiple-point BES Transmission Lines (e.g., two-ended or three-ended lines) are considered to contribute a single weight value per line. For any fault on the line, all line breakers located at the terminals are expected to operate to clear the fault. For example, a single 230 kV three-ended line would contribute an aggregate weighted value of 700 based on the criterion 2.12 table.

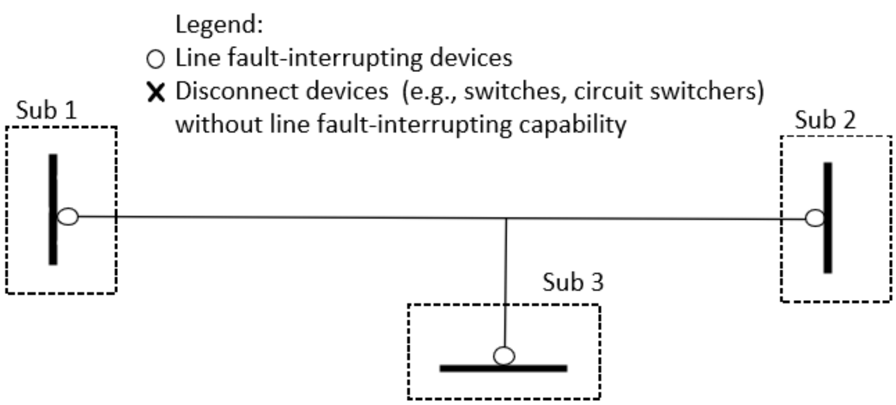


Figure 1: A 230 kV three-terminal Transmission Line contributes an aggregate weighted value of 700

- Multiple-taps BES Transmission Lines (including various implementations such as loop-in-loop-out) are considered to contribute a single weight value per line. For example, a two-ended 230 kV line with two substations tapped on the line where the substations do not have any 230 kV line fault-interrupting devices would contribute an aggregate weighted value of 700 based on the criterion 2.12 table.

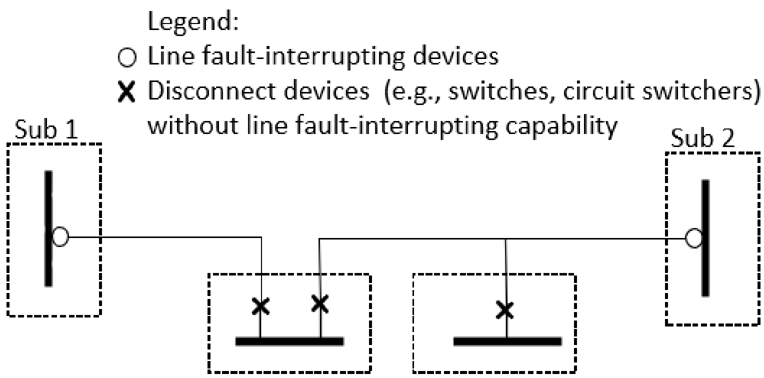


Figure 2: A 230 kV two-terminal Transmission Line with two tapped substations contributes an aggregate weighted value of 700

- Multiple lines between two transmission stations or substations are considered to contribute multiple weight values per line. For example, two two-ended 345 kV lines that connect between the same two transmission stations or substations would contribute an aggregate weighted value of 2,600 based on the criterion 2.12 table.

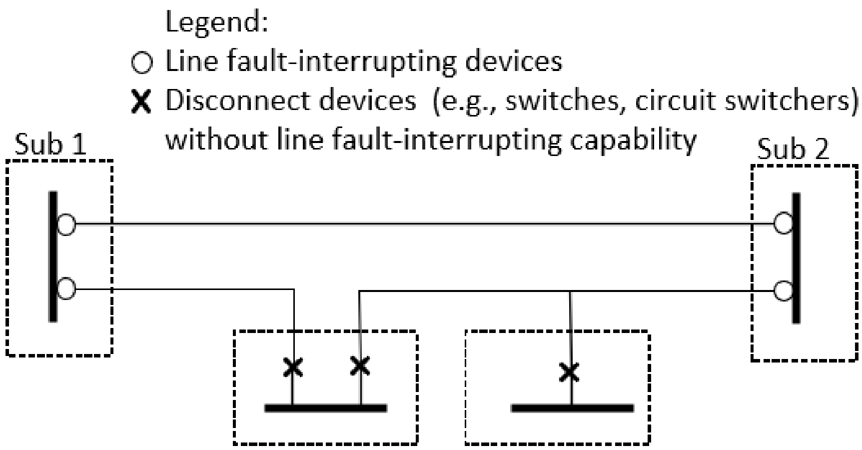


Figure 3: Two 345 kV two-terminal Transmission Lines that connect between the same two Transmission stations or substations contribute an aggregate weighted value of 2,600

Applying the Exclusion Clause per Criterion 2.12

An exclusion clause has been provided to allow Responsible Entities to appropriately categorize their BES Cyber Assets at Control Centers at a level that is commensurate with the associated risk for local systems having limited flow-through or generation export, and are primarily designed to serve load.

The exclusion clause applies to TOPs and TOs where the initial calculated aggregated weighted value (AWV) is less than 12,000. In such cases, the TOP/TO may calculate a revised AWV that excludes those BES Transmission Lines that are contained in a single group of contiguous Elements (GCE[3]) operated at or greater than 69 kV but less than 300 kV, as defined by the Responsible Entity. The hourly integrated gross export from the GCE must not exceed 75 MWh during the preceding 12 calendar months during non-Energy Emergency Alert (EEA) conditions. Gross exports from the GCE during an EEA condition that exceed 75 MWh are allowed to enable the Responsible Entity to provide support to neighboring entities during EEA conditions without any compliance impact.

Entities that choose to pursue an exclusion under criterion 2.12 are responsible for documenting the process whereby they will calculate the hourly integrated gross export from the defined GCE. The concept of an hourly integrated value was selected to avoid requiring entities to use an instantaneous value. There is no requirement that entities install meters specifically for the purpose of calculating the hourly integrated gross export; however, they may do so if they choose. Alternatively, entities may choose to use SCADA data for the purposes of calculating the hourly integrated value.

An entity is responsible to clearly define the GCE and to monitor flows across the interfacing equipment

[3] The concept of a "group of contiguous Elements" will be referred to as a GCE throughout the remainder of this document for simplicity. The acronym is solely used in this document and is not included as a defined term in the NERC Glossary of Terms.

in order to demonstrate compliance with CIP-002. Interfacing equipment is not limited to BES Transmission Lines, provided that the entity is able to collect the necessary data to demonstrate gross export from the GCE remains below 75 MWh. The GCE may contain Elements that the Control Center is not able to control, provided that the GCE boundary encompasses a transmission network that is primarily designed to serve load. The GCE specifically excludes Transmission Lines 300kV and above, as they are generally intended for the bulk transfer of power and not for local load serving purposes. A restriction to allow the responsible entity to define only one GCE is established to prohibit the ability of the entity to segment off multiple areas within a larger geographic area.

An initial calculated AWV of 12,000 is established to avoid application of the exclusion to large control areas. The AWV of 12,000 corresponds to an entity with no single station or substation that meets criterion 2.5, but who has the capability or authority to control BES Transmission Lines with the equivalent weight of four stations or substations whose BES Cyber Systems would be classified as medium impact per criterion 2.5. During the Field Test performed by the DT, entities with AWV between 500 and 11,300 were evaluated and no reliability risks to the BES were identified for any entities.

The bright line of 75 MWh is selected to align with pre-existing criteria including (1) the registration criteria for a Distribution Provider (DP) and (2) the registration criteria for a GO. Establishing a threshold is intended to differentiate between non-impactful load serving areas and areas that are more likely to have an impact on the interconnected BES. It was selected to be conservative and is below other established thresholds such as the reporting requirement for uncontrolled loss of firm load resulting from a BES Emergency and firm load shedding resulting from a BES Emergency as documented in EOP-004. EEA conditions were specifically excluded to ensure a Responsible Entity is not disincentivized from providing all available assistance during emergency conditions due to future compliance considerations.

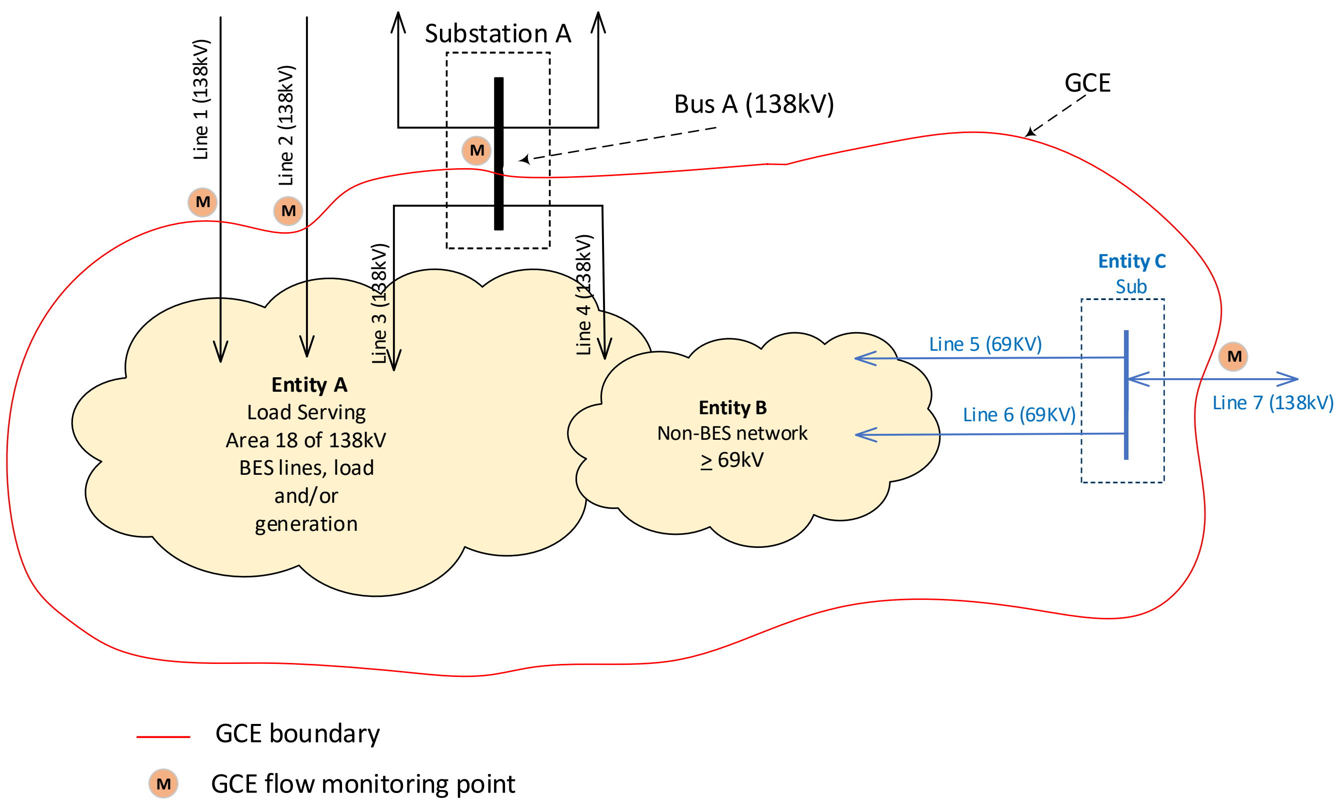
The DT has intentionally constructed the exclusion clause to require an entity to measure gross export from their defined GCE. This accounts for both generation output and flow-through the GCE. It ensures that an entity is unable to define a GCE that contains significant generation that supports the BES or with significant flow-through that impacts the BES.

GCE Example

The GCE must be a contiguous system. It may contain non-BES assets that are operated at 69kV or above and it may contain assets owned/operated by another entity. In the event that a non-BES element is part of the GCE interface, it will need to be included in the gross export calculation.

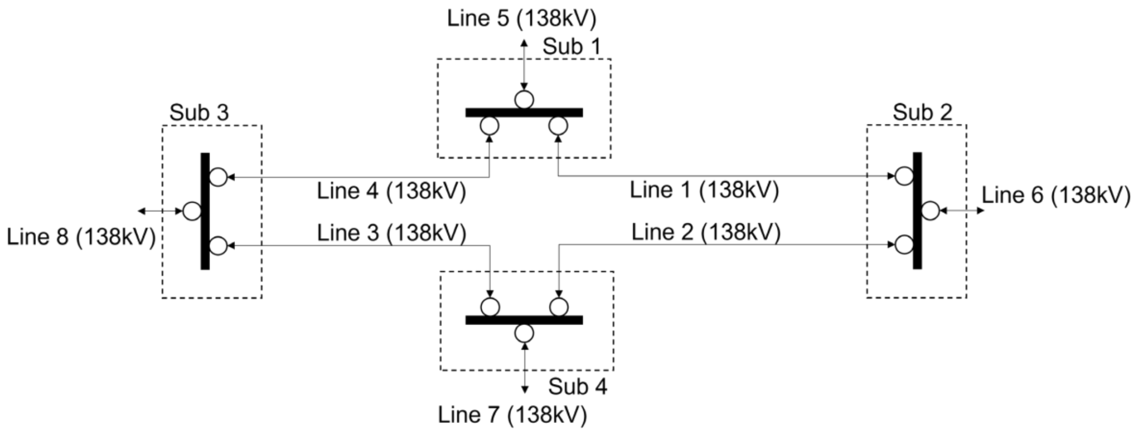
In this example, Entity A defines a GCE that contains all equipment shown in the red boundary below. The GCE interface consists of the flow through Bus A, Line 1, Line 2, and Line 7. The GCE contains equipment owned and operated by Entities A, B and C. To demonstrate compliance with the exclusion clause, Entity A must be able to obtain the necessary data from Entity C for Line 7 to calculate the gross export to demonstrate compliance with CIP-002. The entity must also be able to determine the relevant flow through Bus A, Line 1, Line 2, and Line 7 to demonstrate that gross export from the GCE does not exceed 75 MWh.

In this particular example, Entity A may not have the capability to measure the flow through Bus A; however, the entity may be able to utilize existing measurement points that exist on the four lines that terminate on Bus A to determine the flow as necessary to calculate the hourly integrated gross export from the GCE.



Criterion 2.12 Example 1: Aggregate Weighted Value below 6,000

In example 1 below, BCS are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12 and sum the weighted values for each BES Transmission Line.



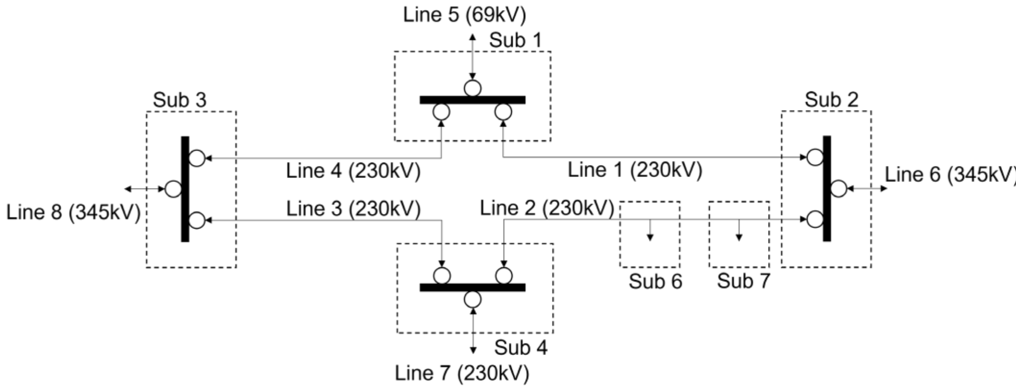
Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2,000, which is below the minimum threshold for the medium impact rating required in criterion 2.12. The BCS associated with the Control Center in this example should be categorized as low impact BCS pursuant to criterion 3.1.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6 Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Criterion 2.12 Example 2: Aggregate Weighted Value exceeds 6,000 with no Exclusion

In example 2 below, BCS are associated with a Control Center that monitors and controls seven BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12 and sum the weighted values for each BES Transmission Line.



Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6,100, which is above the minimum threshold for the medium impact rating required in criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity would be eligible to consider calculating a modified aggregate weighted value that excludes a single GCE in accordance with the exclusion clause; however, in this example, the Responsible Entity either did not choose to pursue an exclusion or did not meet the exclusion criteria. In accordance with criterion 2.12, the BCS associated with the Control Center should be categorized as medium impact BCS.

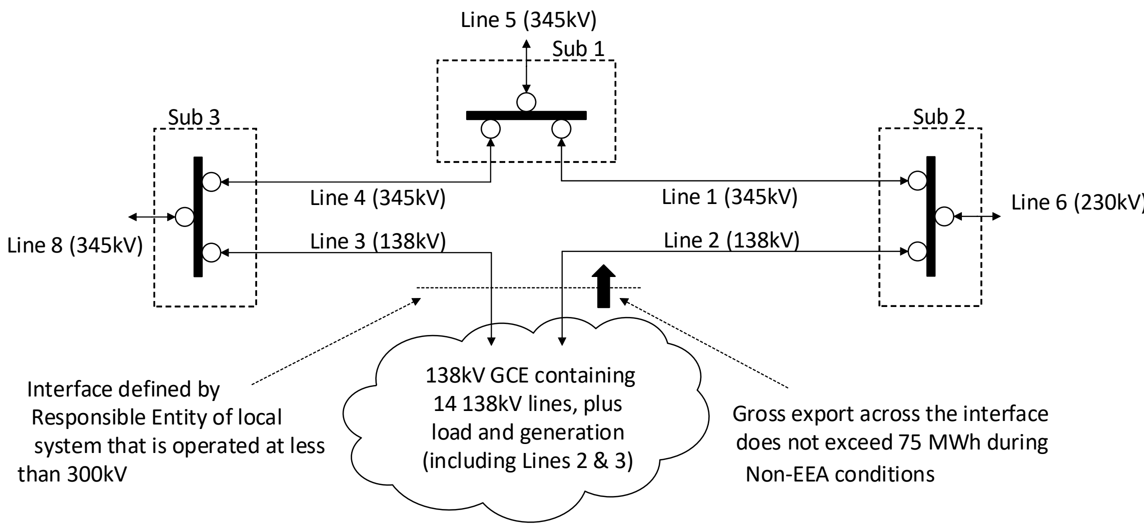
The circles on the diagram indicate the presence of fault-interrupting devices. There are two substations shown (Sub 6 and Sub 7) that are tapped on Line 2 for load serving purposes; however, these substations do not have line fault-interrupting devices that will operate for a fault on Line 2. Therefore, the BES Transmission Line is defined between Sub 2 and Sub 4.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

*Line 5 is less than 100 kV; however, no exception has been obtained through the NERC ROP Exception Process and therefore, the line is not BES.

Criterion 2.12 Example 3: Aggregate Weight Value below 6,000 after Applying GCE Exclusion

In example 3 below, BCS are associated with a Control Center that monitors and controls nineteen BES Transmission Lines, of which 14 are to be excluded from the calculation using the GCE exception. The entity should first calculate its aggregate weighted value, referencing the table located in criterion 2.12. The entity is eligible to calculate a modified aggregate weighted value if the original aggregate weighted value is less than 12,000. In order to calculate the Control Center's modified aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12, and the exclusion language, and sum the weighted values for each BES Transmission Line that is not part of a single GCE that was defined by the entity in accordance with the exclusion clause.



Note: Substation equipment (e.g., transformers) is not shown for simplicity.

Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 9,400, which is above the minimum threshold for the medium impact rating required in criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity is eligible to calculate a modified aggregate weighted value that excludes a single GCE in accordance with the exclusion clause.

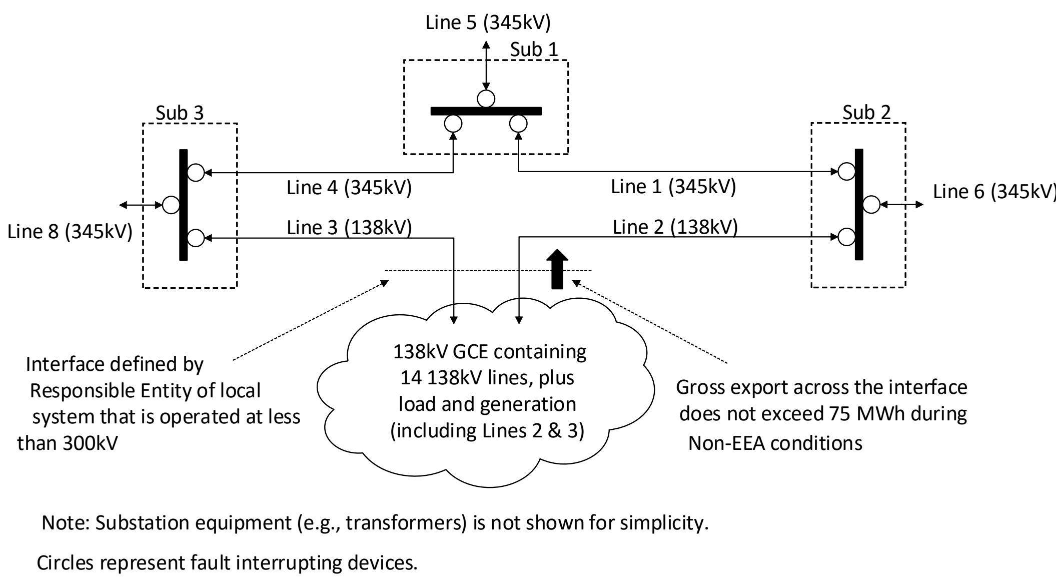
Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 2, Line 3, 12 additional lines	3500
200 kV to 299 kV	700	Line 6	700
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 8	5200
500 kV and above	0	None	0

The calculation of the modified aggregate weighted value is demonstrated below and equates to an aggregate weighted value of 5,900, which is below the minimum threshold for the medium impact rating required in criterion 2.12. The BCS associated with the Control Center in this example should be categorized as low impact BCS pursuant to criterion 3.1.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 6	700
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 8	5200
500 kV and above	0	None	0

*Lines 2 and 3 (along with the 12 additional lines located in the 138 kV GCE) are excluded from the calculation because the Responsible Entity has defined an interface to a GCE that is operated at less than 300kV, where the gross export across the interface does not exceed 75 MWh during non-EEA conditions.

Example 4: Aggregate Weight Value above 6,000 after Applying GCE Exclusion
In example 4 below, BCS are associated with a Control Center that monitors and controls 19 BES Transmission Lines, of which 14 are to be excluded from the calculation using the GCE exception. The entity should first calculate its aggregate weighted value, referencing the table located in criterion 2.12. The entity is eligible to calculate a modified aggregate weighted value if the original aggregate weighted value is less than 12,000. To calculate the Control Center's modified aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12, and the exclusion language, and sum the weighted values for each BES Transmission Line that is not part of a single GCE that was defined by the entity in accordance with the exclusion clause.



The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 10,000, which is above the minimum threshold for the medium impact rating required in criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity is eligible to calculate a modified aggregate weighted value that excludes BES Transmission Lines contained in a single GCE in accordance with the exclusion clause.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 2, Line 3, 12 additional lines	3500
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 6, Line 8	6500
500 kV and above	0	None	0

The calculation of the modified aggregate weighted value is demonstrated below and equates to an aggregate weighted value of 6,500, which is above the minimum threshold for the medium impact rating required in criterion 2.12. In accordance with criterion 2.12, the BCS associated with the Control Center should be categorized as medium impact BCS.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 6, Line 8	6500
500 kV and above	0	None	0

*Lines 2 and 3 (along with the 12 additional lines located in the 138kV GCE system) are excluded from the calculation because the Responsible Entity has defined an interface to a GCE that is operated at less than 300kV, where the gross export across the interface does not exceed 75 MWh during non-EEA conditions.

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Exhibit E

Summary of Development
and Complete Record of Development

Summary of Development History

The following is a summary of the development record for proposed Reliability Standard CIP-002-8 developed under Project 2021-03. Project 2021-03 is assigned four separate Standards Authorization Requests ("SARs"). The currently proposed revisions to CIP-002 are in response to the Project 2016-02 SAR to address the categorization of certain Transmission Owner Control Centers performing Transmission Operator functions as medium impact based on an aggregate weighted value of their Bulk Electric System ("BES") Transmission Lines in Criterion 2.12 of Attachment 1 to the standard. An overview of the development process is detailed below followed by the completed record of development.

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 drafting team ("DT") selected to lead each project in accordance with Section 4.3 of the NERC Standard Processes Manual.[2] For this project, the DT consisted of industry experts, all with a diverse set of experiences. A roster of the Project 2021-03 DT members is included in **Exhibit F**.

II. Standard Development History

A. Standard Authorization Request Development and Project Initiation

At its March 17, 2021 meeting, the NERC Standards Committee voted to authorize soliciting nominations for a DT to determine appropriate criteria for categorizing Transmission

[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/AboutNERC/Pages/Rules-of-Procedure.aspx.

Owner Control Centers in the CIP-002 Standard and assign that portion of the Project 2016-02 SAR which related to Transmission Owner Control Centers to the new DT, Project 2021-03.[3]

The Standards Committee posted solicitation for Project 2021-03 DT members from March 22, 2021 – April 27, 2021. The Standards Committee appointed members to the DT at its May 19, 2021 meeting.[4]

B. Field Test

After being assigned the Project 2016-02 SAR relating to Transmission Owner Control Centers, the Project 2021-03 DT developed a Field Test Plan to obtain data from Transmission Owners and Transmission Operators in order to validate that proposed Criterion 2.12 in Attachment 1 would not expose the Bulk Electric System to increased risk.

The Standards Committee approved the Field Test Plan on November 17, 2021.[5] The final report from the field test was released in January 2023.[6]

C. Supplemental Drafting Team Nominations

Due to the addition of multiple SARs to Project 2021-03, NERC staff recommended appointing additional members to the DT. Supplemental drafting team nominations were posted from May 23, 2022 – June 22, 2022. The Standards Committee appointed the supplemental DT

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3 NERC, *Minutes – Standards Committee Conference Call* at agenda item 5 (Project 2016-02 CIP-002 Field Test) (Mar. 17, 2021), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_March_Meeting_Minutes_Approved_May_19_%202021.pdf.

4 NERC, *Minutes – Standards Committee Conference Call* at agenda item 6 (Project 2021-03 CIP-002 Transmission Owner Control Centers Standard Drafting Team) (May 19, 2021), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC_May_Meeting_Minutes_Approved_June_16_%202021.pdf.

5 NERC, *Minutes – Standards Committee Conference Call* at agenda item 7 (Project 2021-03 CIP-002 Transmission Owner Control Center Field Test) (Nov. 17, 2021), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20November%20Meeting%20%20Minutes%20-%20Approved%20December%2015,%202021.pdf.

6 NERC Project 2021-03 – CIP-002 Transmission Owner Control Center Field Test Final Report (Jan. 2023), https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

members to Project 2021-03 CIP-002 Transmission Owner Control Center (TOCC) at is September 21, 2022 meeting.[7]

Further supplemental nominations were posted from July 20, 2023 – August 18, 2023. The NERC Standards Committee appointed the additional members to the Project 2021-03 CIP-002 DT at its December 13, 2023 meeting.[8]

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

On September 20, 2023, the Standards Committee authorized initial posting of proposed Reliability Standard CIP-002-Y, the associated Implementation Plan, and other associated documents for a 45-day formal comment period from September 26, 2023 – November 9, 2023, 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 31, 2023 – November 9, 2023.[9] The initial ballot and non-binding poll results for the proposed Reliability Standard are as follows:

- Proposed Reliability Standard CIP-002-Y received 32.54 percent approval, reaching quorum at 88.89 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 34.22 percent supportive opinions, reaching quorum at 88.13 percent of the ballot pool.[10]

[7] NERC, *Minutes – Standards Committee Meeting* at agenda item 4 (Project 2021-03 CIP-002 Transmission Owner Control Center) (Sept. 21, 2022), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20September%20Minutes%20-%20Approved%20October%2019,%202022.pdf.

[8] NERC, *Minutes – Standards Committee Conference Call* at agenda item 7 (Project 2021-03 CIP-002) (Dec. 13, 2023), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20December%20Minutes%20-%20Approved%20January%2017,%202024.pdf.

[9] NERC, *Minutes – Standards Committee Meeting* at agenda item 7 (Project 2021-03 CIP-002) (Sept. 20, 2023), https://www.nerc.com/comm/SC/Agenda%20Highlights%20and%20Minutes/SC%20September%20Minutes%20-%20Approved%20Noveber%2015,%202023.pdf.

[10] Exhibit E at items 45, 47.

- The Implementation Plan received 42.55 percent approval, reaching quorum at 90.69 percent of the ballot pool.[11]

There were 78 sets of responses, including comments from approximately 172 different individuals and approximately 111 companies, representing all 10 industry segments.[12]

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

Proposed Reliability Standard CIP-002-Y, the associated Implementation Plan, and other associated documents were posted for a 45-day formal comment period from April 2, 2024 – May 16, 2024, with a parallel additional ballot and non-binding poll held during the last 10 days of the comment period from May 7, 2024 – May 16, 2024. The additional ballot and non-binding poll results for the proposed Reliability Standard are as follows:

- Proposed Reliability Standard CIP-002-Y received 47.72 percent approval, reaching quorum at 88.55 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 53.44 percent supportive opinions, reaching quorum at 87.05 percent of the ballot pool.[13]
- The Implementation Plan received 58.73 percent approval, reaching quorum at 88.28 percent of the ballot pool.[14]

There were 67 sets of responses, including comments from approximately 166 different individuals and approximately 100 companies, representing all 10 industry segments.[15]

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11 *Id.* at item 46.
12 *Id.* at item 42.
13 *Id.* at items 59, 61.
14 *Id.* at item 60.
15 *Id.* at item 56.

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

Proposed Reliability Standard CIP-002-8, the associated Implementation Plan, and other associated documents were posted for a 45-day formal comment period from August 29, 2024 – October 15, 2024, with a parallel additional ballot and non-binding poll held during the last 10 days of the comment period from October 4, 2024 – October 15, 2024. The additional ballot and non-binding poll results for the proposed Reliability Standard are as follows:

- Proposed Reliability Standard CIP-002-8 received 83.05 percent approval, reaching quorum at 88.89 percent of the ballot pool. The non-binding poll for the associated VRFs and VSLs received 80.11 percent supportive opinions, reaching quorum at 85.61 percent of the ballot pool.[16]
- The Implementation Plan received 89.07 percent approval, reaching quorum at 88.28 percent of the ballot pool.[17]

There were 63 sets of responses, including comments from approximately 165 different individuals and approximately 105 companies, representing all 10 industry segments.[18]

G. Final Ballot

Proposed Reliability Standard CIP-002-8 was posted for a 10-day final ballot period from November 13, 2024 – November 22, 2024. The final ballot for proposed Reliability Standard CIP-002-8 reached quorum at 87.12 percent of the ballot pool, receiving support from 90.24 percent of the voters. The final ballot for the Implementation Plan reached quorum at 90 percent of the ballot pool, receiving support from 91.31 percent of the voters.[19]

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16 *Id.* at items 74, 76.
17 *Id.* at item 75.
18 *Id.* at item 71.
19 *Id.* at items 83, 84.

H. Board of Trustees Adoption

At its December 10, 2024 meeting, the NERC Board of Trustees adopted proposed Reliability Standard CIP-002-8, the Implementation Plan, the VRFs and VSLs, and the retirement of CIP-002-7.[20]

[20] NERC, *Board of Trustees Agenda Package Dec. 10, 2024*, Agenda Item 3c (Project 2021-03 CIP-002), 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 2021-03 CIP-002

Related Files

Status

Final ballots concluded at **8 p.m. Eastern, Friday, November 22, 2024** for the following standard and implementation plan:

- CIP-002-8 — Cyber Security - BES Cyber System Categorization
- Implementation Plan

Based on recent board adopted standard CIP-002-7, the posted version for 2021-03 CIP-002 reflects CIP-002-8. The Standards Balloting and Commenting System (SBS) does not allow edits once a ballot is created and/or opened. Even though the standard versioning within the SBS states CIP-002-Y, the version number within this posting is correct and entities voted on CIP-002-8.

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

Background/Purpose

The Standards Committee (SC) has tasked the Project 2021-03 standard drafting team (SDT) with the following:

1. Transmission Owner Control Centers (TOCCs) – The SC assigned a portion of the Project 2016-02 SAR that relates to TOCCs to the Project 2021-03 SDT. That SAR portion is to review CIP-002 and evaluate the categorization of TOCCs performing the functional obligations of a Transmission Operator, specifically those that meet medium impact criteria. In addition, this SDT is assisting NERC staff in meeting the directive from the NERC Board of Trustees to conduct further study of the need to readdress the applicability of the Critical Infrastructure Protection Reliability Standards to these Control Centers to support reliability. To help meet this directive and the scope of the SAR, the SDT initiated a field test. The SC approved the Project 2021-03 Field Test Plan on November 17, 2021. There were three field tests conducted and the SDT is working on modifications to the CIP-002 Criterion 2.12 and the Control Center definition.

2. CIP-002 and CIP-014 – This SAR provides revisions to CIP-002 and CIP-014 to clarify the responsibility of Reliability Coordinators, Planning Coordinators, and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards. As it relates to the Transmission Planner and Planning Coordinator functions, the language "critical to the derivation of Interconnection Reliability Operating Limits (IROLs)" should be replaced/updated to appropriately identify Facilities that, if somehow compromised, could significantly impact the reliability of the Bulk Electric System (BES). Additionally, this SAR includes a review of the applicability of Facilities identified by the Reliability Coordinator as critical to the derivation of IROLs to CIP-002 and CIP-014. The SC accepted this SAR on July 21, 2021.

3. CIP-002 SAR for Requirement R1 Parts 1.1 – 1.3 – This Standard Authorization Request is to consider if such a protocol converter meets the definition of a BES Cyber Asset by having an adverse impact to one or more facilities and the reliable operation on the BES. This includes consideration to the threat of unavailability, degradation, or misuse to a connected BES Cyber System and the aggregation of serial system-to-system communications from substations to Control Center BES Cyber Systems. As such, this project supports reliability by clarifying how these protocol converters should be categorized and if they are to reside within a defined Electronic Security Perimeter.

4. CIP-002-5.1a Criterion 1.3 Revision - This SAR seeks to require the TOP to categorize its BES Cyber System(s) as high impact that meet Criterion 2.6 as is also required of the BA and GOP in Criterion 1.2 and 1.4, respectively. By including Criterion 2.6 in Criterion 1.3, the TOP's BES Cyber Systems(s) will be properly categorized as high impact for Transmission Facilities at a single station or substation location that is identified as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

Standard(s) Affected – CIP-002: Cyber Security – BES Cyber System Categorization and CIP-014: Physical Security

Draft	Actions	Dates	Results	Consideration of Comments
Final Draft **CIP-002-8** Clean **(77)** | Redline to Last Approved **(78)** | Redline to Last Posted**(79)** *updated Implementation Plan **(80)** **Supporting Materials** Technical Rationale (**81)**	Final Ballot Info **(82)** Vote	11/13/24 - 11/22/24	Ballot Results CIP-002-8 **(83)** Implementation Plan **(84)**	
Draft 3 CIP-002-8 Clean **(63)** | Redline to Last Approved **(64)**| Redline to Last Posted **(65)** Implementation Plan **(66)** **Supporting Materials** Unofficial Comment Form (Word) **(67)** Technical Rationale **(68)**	Additional Ballots and Non-binding Poll Ballot Open Reminder **(72)** Info **(73)** Vote	10/04/24 - 10/15/24	Ballot Results CIP-002-8 **(74)** Implementation Plan **(75)** Non-binding Poll **(76)**	
	Comment Period Info **(69)**	08/29/24 - 10/15/24	Comments Received **(70)**	Consideration of Comments **(71)**

	Submit Comments			
CIP-002-5.1a and CIP-014-2 Standard Authorization Request (62)	The Standards Committee authorized drafting new or modified Reliability Standards as identified in the SAR on June 12, 2024			
Draft 2 CIP-002-Y Clean (48) | Redline to Last Posted (49) | Redline to Last Approved (50) Implementation Plan (51) **Supporting Materials** Unofficial Comment Form (Word) (52) Technical Rationale (53)	Additional Ballots and Non-binding Poll Ballot Open Reminder (57) Info (58) Vote	05/07/24 - 05/16/24	Ballot Results CIP-002-Y (59) Implementation Plan (60) Non-binding Poll Results (61)	
	Comment Period Info (54) Submit Comments	04/02/24 - 05/16/24	Comments Received (55)	Consideration of Comments (56)
Draft 1 CIP-002-Y Clean (35) | Redline (36) Implementation Plan (37) **Supporting Materials** Unofficial Comment Form (Word) (38) Technical Rationale (39)	Initial Ballots and Non-binding Poll Ballot Open Reminder (43) Info (44) Vote	10/31/23 - 11/09/23	Ballot Results CIP-002-Y (45) Implementation Plan (46) Non-binding Poll Results (47)	
	Join Ballot Pools	09/26/23 - 10/25/23		
	Comment Period Info (40) Submit Comments	09/26/23 - 11/09/23	Comments Received (41)	Consideration of Comments (42)
Supplemental Drafting Team Nominations **Supporting Materials** Unofficial Comment Form (Word) (33)	Nomination Period Info (34) Submit Nominations	07/20/23 - 08/18/23		
CIP-002-5.1a Criterion 1.3 Revisions SAR (29) **Supporting Materials** Unofficial Comment Form (Word) (30)	Comment Period Info (31) Submit Comments	07/20/23 - 08/18/23	Comments Received (32)	
Proposed Standard language that addresses: **Control Center Definition** **New Definition for Data Center** **CIP-002-5.1a Criterion 2.12 with Exclusion process** Unofficial Comment Form (Word) (26)	Comment Period Info (27) Submit Comments	06/13/23 - 07/12/23	Comments Received (28)	
CIP-002 Communications Protocol Converters SAR (22) **Supporting Materials** Unofficial Comment Form (Word) (23)	Comment Period Info (24) Submit Comments	03/02/23 - 03/31/23	Comments Received (25)	
Field Test Final Report (21)	For informational purposes			
Standard Authorization Requests Modifications_to_CIP-002 (15) CIP-002-5.1a_and_CIP-014-2 (16)	Comment Period Info (18) Submit Comments	11/22/22 - 12/21/22	Comments Received (19)	Consideration of Comments (20)

Supporting Materials Unofficial Comment Form (Word) **(17)**				
Field Test Third Questionnaire CIP-002 TOCC Field Test Questionnaire 3 **(14)**	The questionnaire was sent to the field test participants on September 14, 2022	09/14/22 - 10/04/22		
Supplemental Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form **(12)**	Nomination Period Info **(13)** Submit Nominations	05/23/22 - 06/22/22		
Request for Interpretation CIP-002-5.1a SAR (11)	The Standards Committee rejected the CIP-002-5.1a – Serial Communications Request For Interpretation (RFI) submitted by Burns & McDonnell on February 22, 2023			
Modifications to CIP-002 SAR (10)	The Standards Committee accepted the SAR on February 16, 2022			
Field Test Second Questionnaire CIP-002 TOCC Field Test Questionnaire 2 **(8)** Power Flow Instruction Document **(9)**	The questionnaire was sent to the field test participants on February 22, 2022	02/22/22 - 04/01/22	Summary of Responses Received (Questionnaire 1 and 2) **(7)**	
Field Test First Questionnaire CIP-002 TOCC Field Test Questionnaire 1 **(6)**	The questionnaire was sent to the field test participants on January 10, 2022	01/10/22 - 02/07/22	Summary of Responses Received (Questionnaire 1 and 2) **(7)**	
CIP-002 TOCC Field Test Plan **(5)**	The Standards Committee approved the Field Test Plan on November 17, 2021			
CIP-002 and CIP-014 SAR **(4)**	The Standards Committee accepted the SAR on July 21, 2021			
2016-02 SAR **(3)**	The Standards Committee accepted the SAR on March 17, 2021			
Drafting Team Nominations **Supporting Materials** Unofficial Nomination Form (Word) **(1)**	Nomination Period Info **(2)** (updated) Submit Nominations	03/22/21 – 04/27/21 (extended)		

Unofficial Nomination Form

Project 2021-03 CIP-002 Transmission Owner Control Centers (TOCC)

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **Project 2021-03 CIP-002 Transmission Owner Control Centers (TOCC)** standard drafting team (SDT) members by **8 p.m. Eastern, Tuesday, April 20, 2021.** This unofficial version is provided to assist nominees in compiling the information necessary to submit the electronic form.

Additional information is available on the project page. If you have questions, contact Manager of Standards Development, Latrice Harkness (via email), or at 404-446-9728.

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.

Project 2021-03 CIP-002 Transmission Owner Control Centers (TOCC)
On May 14, 2020, the NERC Board of Trustees (Board) adopted proposed Reliability Standard CIP-002-6. The proposed standard revised Criterion 2.12 to categorize certain Transmission Owner Control Centers (TOCCs) performing Transmission Operator functions as medium impact based on an aggregate weighted value of their Bulk Electric System (BES) Transmission Lines. The Project 2016-02 SAR was accepted by the Standards Committee on July 20, 2016, which includes the scope for addressing the TOCC obligations.

On June 12, 2020, NERC staff filed with the Federal Energy Regulatory Commission (FERC) a petition for approval of proposed CIP-002-6. On June 23, 2020, the proposed standard was filed with the applicable regulatory authorities in Canada.

At its February 4, 2021 meeting, the Board withdrew proposed Reliability Standard CIP-002-6. In addition, the Board issued a resolution stating "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers[1] to safeguard reliability, for the purpose of recommending further action to the Board." On February 5, 2021, NERC filed a notice of withdrawal for CIP-002-6 with FERC.

NERC is soliciting nominations for a standard drafting team to gather relevant data and determine the appropriate criteria for categorizing Transmission Owner Control Centers (TOCCs) as medium impact in the CIP-002 Reliability Standard. The purpose of Reliability Standard CIP-002 is to identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES

[1] In this context, Control Centers refers to those owned by Transmission Owners performing the functional obligations of a Transmission Operator.

Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

The scope of work for the standard drafting team is to review CIP-002 and evaluate the categorization of Transmission Owner (TO) Control Centers performing the functional obligations of a Transmission Operator (TOP), specifically those that meet medium impact criteria. This standard drafting team is tasked with assisting NERC staff in meeting the directive from the NERC Board to conduct further study of the need to readdress the applicability of the CIP Reliability Standards to these Control Centers to support reliability. As such, data will be evaluated to determine the appropriateness of a bright line or to recommend further action.

NERC is seeking individuals from the United States and Canada who possess experience in one or more of the following areas:

- Network and externally accessible devices
- Cyber Asset and BES Cyber Asset definitions
- Transmission Owner (TO) Control Centers and how they interconnect with the BES, associated Cyber Assets and the application of CIP-002 Criterion 2.12
- Critical Infrastructure Protection (“CIP”) family of Reliability Standards
- Operations and Protections

The time commitment is expected to be significant. Participants should anticipate an average workload of 15 hours per week devoted to the drafting team efforts. There will be up to two virtual meetings weekly with additional virtual meetings 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.

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:	

UPDATED

Standards Announcement

Project 2021-03 CIP-002 Transmission Owner Control Centers (TOCC)

Nomination Period Now Open through April 27, 2021

Now Available

Nominations are being sought for **Project 2021-03 CIP-002 Transmission Owner Control Centers** standard drafting team (SDT or team) members. The due date has been extended, and is now open through **8 p.m. Eastern, Tuesday, April 27, 2021**.

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

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

The time commitment is expected to be significant. Participants should anticipate an average workload of 15 hours per week devoted to the drafting team efforts. There will be up to two virtual meetings weekly with additional virtual meetings 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.

Previous SDT experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the SDT in May 2021. Nominees will be notified shortly after they have been appointed.

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

For more information or assistance, contact Manager of Standards Development, Latrice Harkness (via email) or at 404-446-9728. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-03 CIP-002 Transmission Owner Control Centers (TOCC)” 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 Authorization Request Form

When completed, email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard(s):	Modifications to CIP Standards		
Date Submitted:	June 1, 2016		
SAR Requester Information			
Name:	Stephen Crutchfield		
Organization:	NERC		
Telephone:	609-651-9455	E-mail:	Stephen.Crutchfield@nerc.net
SAR Type (Check as many as applicable)			
☒ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Purpose (Describe what the standard action will achieve in support of Bulk Electric System reliability.):
The purpose of this project is to (1) consider the Version 5 Transition Advisory Group (V5TAG) issues identified in the *CIP V5 Issues for Standard Drafting Team Consideration* (V5TAG Transfer Document) and (2) address the Federal Energy Regulatory Commission (Commission) directives contained in Order 822. These revisions will increase reliability and security to the Bulk-Power System (BPS) by enhancing cyber protection of BPS facilities.
Industry Need (What is the industry problem this request is trying to solve?):
The V5TAG, which consists of representatives from NERC, Regional Entities, and industry stakeholders, was formed to issue guidance regarding possible methods to achieve compliance with the CIP V5 standards and to support industry's implementation activities. During the course of the V5TAG's activities, the V5TAG identified certain issues with the CIP Reliability Standards that were more appropriately addressed by the existing standard drafting team (SDT) for the CIP Reliability Standards.

SAR Information
The V5TAG developed the V5TAG Transfer Document to explain the issues and recommend that the SDT consider them in future development activity. On January 21, 2016, the Commission issued Order No. 822 approving revisions to the CIP version 5 standards and also directing NERC to develop modifications to address: • Protection of transient electronic devices used at low-impact BES Cyber Systems; • Protections for communication network components between control centers; and • Refinement of the Low Impact External Routable Connectivity (LERC) definition. The Commission did not provide a date by which the modifications for transient devices or communication networks must be completed. For the LERC definition, however, the Commission directed that NERC submit the modification within one year of the effective date of Order No. 822 (March 31, 2017).
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The proposed project will consider the issues raised by the V5TAG in the V5TAG Transfer Document and will address the Commission directives in Order No. 822 through modifications to the CIP standards. The work will include development of Violation Risk Factors, Violation Severity Levels, and an Implementation Plan for the modified standards and will meet the deadlines established by the Commission in Order No. 822.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

As stated above, the purpose of this project is to consider the V5TAG issues in the initial transfer document V5TAG Transfer Document and address the Commission directives contained in Order 822. For the directive on the LERC definition, the project is to respond within the deadline required in the order.
 	
As noted above, the V5TAG identified specific issues with the CIP V5 standards. The V5TAG drafted the V5TAG Transfer Document to formally recommend that the SDT address these issues during standards development to consider whether modifications can be made to the standard language. As outlined in the V5TAG Transfer Document, the specific issues are as follows:
• <u>Cyber Asset and BES Cyber Asset (BCA) Definitions</u> – as foundational definitions within the CIP V5 standards, the understanding of Cyber Asset and BCA terms impacts the scope of the applicable requirements. The V5TAG recommends the following enhancements:
  • Clarify the intent of "programmable" in Cyber Asset.
  • Clarify and focus the definition of "BES Cyber Asset" including:
    ▪ Focusing the definition so that it does not subsume all other cyber asset types.
    ▪ Considering a lower bound to the term 'adverse' in "adverse impact".

SAR Information

▪ Clarifying the double impact criteria (cyber asset affects a facility and that facility affects the reliable operation of the BES) such that "N-1 contingency" is not a valid methodology that can eliminate an entire site and all of its Cyber Assets from scope.
• Network and Externally Accessible Devices – V5TAG recommends improving clarity within the concepts and requirements concerning Electronic Security Perimeters (ESP), External Routable Connectivity (ERC), and Interactive Remote Access (IRA) including:
  • The 4.2.3.2 exemption phrase "between discrete Electronic Security Perimeters"
  • The meaning of the word 'associated' in the ERC definition.
  • The applicability of ERC including the concept of the term "directly" used in the phrase "cannot be directly accessed through External Routable Connectivity" within the Applicability section.
  • The IRA definition placement of the phrase "using a routable protocol" in the definition and with respect to Dial-up Connectivity.
  • The Guidelines and Technical Basis sentence, "If dial-up connectivity is used for Interactive Remote Access, then Requirement R2 also applies."
• Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations – V5TAG is aware of multiple interpretations of the language "used to perform the functional obligation of" in CIP-002-5.1 Attachment 1, section 2.12 and recommends clarification of:
  • The applicability of requirements on a TO Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
  • The definition of Control Center.
  • The language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.
• Virtualization – The CIP V5 standards do not specifically address virtualization. Because of the increasing use of virtualization in industrial control system environments, V5TAG asked that the SDT consider the CIP V5 standards and the associated definitions regarding permitted architecture and the security risks of virtualization technologies.
 	
The SDT shall also address the Order No. 822 directives by developing modifications to requirements in CIP standards and the definition of LERC. The Commission directed the following:
 	
• *Per paragraph 32, "...we direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to provide mandatory protection for transient devices used at Low Impact BES Cyber Systems based on the risk posed to bulk electric system reliability. While NERC has flexibility in the manner in which it addresses the Commission's concerns, the proposed modifications should be designed to effectively address the risks posed by transient devices to Low Impact BES Cyber Systems in a manner that is consistent with the risk-based approach reflected in the CIP version 5 Standards."*

SAR Information
• *Per paragraph 53, "…the Commission concludes that modifications to CIP-006-6 to provide controls to protect, at a minimum, communication links and data communicated between bulk electric system Control Centers are necessary in light of the critical role Control Center communications play in maintaining bulk electric system reliability. Therefore, we adopt the NOPR proposal and direct that NERC, pursuant to section 215(d)(5) of the FPA, develop modifications to the CIP Reliability Standards to require responsible entities to implement controls to protect, at a minimum, communication links and sensitive bulk electric system data communicated between bulk electric system Control Centers in a manner that is appropriately tailored to address the risks posed to the bulk electric system by the assets being protected (i.e., high, medium, or low impact)."* • *Per paragraph 73, "…the Commission concludes that a modification to the Low Impact External Routable Connectivity definition to reflect the commentary in the Guidelines and Technical Basis section of CIP-003-6 is necessary to provide needed clarity to the definition and eliminate ambiguity surrounding the term "direct" as it is used in the proposed definition. Therefore, pursuant to section 215(d)(5) of the FPA, we direct NERC to develop a modification to provide the needed clarity, within one year of the effective date of this Final Rule…."* In addition, the SDT will review and address the CIP V5 requirements for CIP Exceptional Circumstances exceptions. Finally, the SDT will review the Guidelines and Technical Basis sections of the CIP V5 standards and adjust where appropriate as well as correct any grammatical, punctuation, and/or formatting errors, and make other errata changes to the CIP V5 standards, as necessary.

Reliability Functions		
The Standard will Apply to the Following Functions (Check each one that applies.)		
☐	Regional Reliability Organization	Conducts the regional activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the Bulk Electric System within the region and adjacent regions.
☒	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions		
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☒	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☒	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☒	Distribution Provider	Delivers electrical energy to the End-use customer.
☒	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and Reactive Power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☐	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

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

Does the proposed Standard comply with all of the following Market Interface Principles?	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

Related Standards	
Standard No.	Explanation

Related Standards	

Related SARs	
SAR ID	Explanation

Regional Variances	
Region	Explanation
FRCC	
MRO	
NPCC	
RF	
SERC	
SPP RE	
Texas RE	
WECC	

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:	Modifications to CIP-002 and CIP-014		
Date Submitted:	May 26, 2021		
SAR Requester			
Name:	Dean LaForest		
Organization:	ISO New England		
Telephone:	413-387-8132	Email:	dlaforest@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?):			
This project provides revisions to CIP-002 and CIP-014 to clarify the responsibility of Reliability Coordinators, Planning Coordinators and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards. As it relates to the Transmission Planner and Planning Coordinator functions, the language "critical to the derivation of Interconnection Reliability Operating Limits (IROLs)" should be replaced/updated to appropriately identify Facilities that, if somehow compromised, could significantly impact the reliability of the Bulk Electric System (BES). Additionally this project will review the applicability of Facilities identified by the Reliability Coordinator as critical to the derivation of IROLs to CIP-002 and CIP-014.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project provides necessary clarification to identify Facilities identified by Reliability Coordinators, Planning Coordinators and Transmission Planners that warrant consideration under the CIP-002 and CIP-014 Reliability Standards. These clarifications will ensure that responsible entities are provided with the			

Requested information
necessary information to appropriately protect these Facilities, and correctly identify the responsible parties that provide the information applicable to the standards.
Project Scope (Define the parameters of the proposed project):
This project will make conforming changes to CIP-002 and CIP-014 as a result of Standard revisions from Project 2015-09. Project 2015-09 revised the requirements for determining and communicating System Operating Limits (SOLs) and IROLs used in the reliable planning and operation of the BES. These revisions necessitate that CIP-002 and CIP-014 be revised to clarify the Functional Entities responsible for communication of Facilities that warrant consideration under the CIP-002 and CIP-014 Reliability Standards. This will include review of criteria/applicability to determine Facilities identified per Attachment 1 of CIP-002 and the Applicability section of CIP-014 for potential revision for responsible entities. This team will work to coordinate with other ongoing CIP development projects to ensure alignment with any changes to definition or standards and requirements.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Revisions to CIP-002 and CIP-014 to include: (1) Identifying Functional Entities that identify Facilities applicable to CIP-002 and CIP-014. (2) Identifying Functional Entities responsible for the communication of the identified Facilities. (3) Applicability sections to be reviewed and revised accordingly. (4) Determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP’s Planning Assessment for the Near-Term Transmission Planning Horizon. (5) Determine the appropriateness of the identification of Facilities critical to the derivation of IROLs by the RC.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact of implementation of the proposed Standard is dependent upon the method(s) by which a Responsible Entity chooses to meet any additional Requirements. However, a question will be asked during the SAR comment period to ensure cost aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
Submitter asserts there are no unique characteristics associated with BES facilities that will be impacted by this proposed standard development project.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
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 2016-02 Modifications to CIP 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.
None at this time.

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.

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

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
	None identified

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

CIP-002 Transmission Owner Control Centers (TOCCs) Field Test

Project 2021-03

Overview

On May 14, 2020, the NERC Board of Trustees (Board) adopted proposed Reliability Standard CIP-002-6. The proposed standard revised Criterion 2.12 to categorize non-high impact Bulk Electric System (BES) Cyber Systems associated with Control Centers performing the reliability tasks of a Transmission Operator (TOP) as medium impact, while moving a subset not meeting the Criterion to be categorized as low impact. This revision was intended to remove uncertainty surrounding the multiple interpretations of the language "used to perform the functional obligation of" in the current Standard and recognize the existence of certain Transmission Owner Control Centers (TOCCs) performing TOP reliability functions as medium impact based on an aggregate weighted value of their Transmission Lines. Further, the revision also recognized the existence of small, registered TOP entity Control Centers having minimal impact to the BES that should be categorized as low impact. The Project 2016-02 SAR was accepted by the Standards Committee on July 20, 2016, which includes the scope for addressing the TOCC obligations.

On June 12, 2020, NERC staff filed with the Federal Energy Regulatory Commission (FERC) a petition for approval of proposed CIP-002-6. On June 23, 2020, the proposed standard was filed with the applicable regulatory authorities in Canada.

At its February 4, 2021 meeting, the Board withdrew proposed Reliability Standard CIP-002-6. In addition, the Board issued a resolution stating "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers[1] to safeguard reliability, for the purpose of recommending further action to the Board." On February 5, 2021, NERC filed a notice of withdrawal for CIP-002-6 with FERC.

The 2021-03 CIP-002 TOCC Standard Drafting Team (SDT) was created to conduct further study and recommend next steps, in response to the following SAR language:

> *Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations – V5TAG is aware of multiple interpretations of the language "used to perform the functional obligation of" in CIP-002-5.1 Attachment 1, section 2.12 and recommends clarification of:*
>
> - *The applicability of requirements on a TO Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.*
> - *The definition of Control Center.*
> - *The language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.*

As such, the SDT has designed a Field Test to obtain data from TOs and TOPs for the explicit purpose to validate that the proposed bright line Criterion 2.12 shown below is appropriate and does not expose the Bulk Electric System to vulnerabilities. The inclusion of TOPs in the Field Test is necessary since the functional registration of an entity is not expressly assigned. Further, the SDT recognizes the TOs' need for clarification on identifying whether they may own and operate a control room that could qualify as a *Control Center used to perform the reliability tasks of a Transmission Operator,* and is provided in Attachment A.

The expected outcome of the Field Test is to recommend the appropriate bright line criteria. This may mean that: (1) the current bright line Criterion 2.12 language (shown below) is retained, (2) the proposed bright line Criterion 2.12 language (shown below) remains justified with additional technical basis, or (3) a new bright line Criterion 2.12 is recommended based on the technical results obtained from the Field Test.

Current bright line Criterion 2.12 from CIP-002-5.1a:

> [Each BES Cyber System, not included in Section 1 above, associated with] Each Control Center or backup Control Center used to perform the functional obligations of a Transmission Operator, not included in High Impact Rating above [shall be Medium Impact].

Proposed bright line Criterion 2.12 from withdrawn CIP-002-6:

> [Each BES Cyber System, not included in Section 1 above, associated with] Each Control Center or backup Control Center, not included in the High Impact Rating, used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines with an "aggregated weighted value" exceeding 6000 according to the table below [shall be Medium Impact]. The "aggregated weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

TOCC Field Test Preparation

Successful completion of the Field Test requires an adequate pool of participants whose aggregated weighted value as defined in the proposed Criterion 2.12 falls near 6000, both above and below. While assuring all BES Cyber Systems are appropriately categorized as medium impact is paramount, it is also important to assure compliance resources are expended commensurate to the reliability risk. Entities owning BES Transmission Lines with an "aggregated weighted value" exceeding 6000 and have a lower inherent risk to the BES are encouraged to participate in the TOCC Field Test. The following guideline should be followed to determine if participating in the Field Test is appropriate.

- TOCC Entity formerly afforded discretionary enforcement designating a Control Center as low impact.
- TOCC Entity holding a contractual agreement with a second party who provides cover as the registered TOP, and owns/operates a “TO Dispatch Center” as defined in Attachment A.
- TOP Entity whose “aggregated weighted value” is 6000 or less and has no high impact BES Cyber System associated with its Control Center or Backup Control Center.
- TOP Entity whose “aggregated weighted value” is 6000 or greater and has no:
  - Identified Interconnection Reliability Operating Limit (IROL)
  - Remedial Action Scheme (RAS)
  - Substantial role in voltage or frequency control, such as:
    - Control of, or directly interconnected BES Generation above 1500 MW or BES reactive resource above 1000 MVAR.
    - Automatic Load Shedding of 300 MW or more

Transmission Owners and Transmission Operators who would like to participate in the TOCC Field Test are encouraged to contact Jordan Mallory. Each entity interested in participating in the TOCC Field Test must provide the following:

1. Provide NERC staff with the name, phone number, and email address of:
   a. The primary contact for the TOCC Field Test,
   b. The contact for the director/manager/supervisor over CIP Compliance,
   c. The contact for the CIP Senior Manager, if different from the above, and
   d. The primary compliance contact for its registered entity

Participating entities should have the capability to perform necessary steady state and dynamic simulations OR be willing to engage with a consultant (individually or jointly) to perform such studies. After the Field Test has been approved, the Reliability and Security Technical Committee can identify other Field Test participants. Information received from participating TOs and TOPs will be treated as confidential.

TOCC Field Test Compliance and Enforcement Discretion

The SDT will keep the participant and proposed participant list non-public and protect any information meeting the NERC Rules of Procedure (ROP) definition of Confidential Information as required by Section 1500 of the NERC ROP.

The name of a participant may be released to a participating entity's Regional Entity, at the request of the participant, as necessary to facilitate waivers of compliance that have been issued by CMEP staff.

The purpose of collecting information from participants is to support the SDT's assessment of impact to the BES rather than for compliance purposes. Nevertheless, entities must continue to comply with all applicable Reliability Standards, except as described in this section.

Per Section 6.1.2 of the Standard Processes Manual, the NERC Compliance Monitoring and Enforcement Program (CMEP) staff, at its discretion, may grant waivers of compliance to Field Test participants if participation in the Field Test renders them incapable of complying with the currently-enforceable Reliability Standard.

Participating TOPs, and TOs already complying with medium impact requirements, will continue to be responsible for compliance under the NERC Standards, including but not limited to, CIP-002-5.1a "Cyber Security – BES Cyber System Categorization" for the duration of the TOCC Field Test.

If TOs currently applying low impact requirements to a Control Center meeting Criterion 2.12 and were notified they need to become medium impact by October 1, 2023, participation in the Field Test will permit them to continue applying low impact requirements until conclusion of the Field Test, with a reasonable period of time permitted for them to become compliant with medium impact requirements if applicable once the revised standard language is developed.

TOCC Field Test Questionnaires and Reporting

During the TOCC Field Test, the TOCC SDT will issue participants a series of questionnaires with the ultimate intention of determining whether there is adequate technical justification to modify CIP-002 such that BES Cyber Assets at additional TOP and TOCCs can be classified as low impact without jeopardizing BES system reliability. The initial questionnaire, provided in Attachment B, is designed to obtain information about various company-specific attributes that will aid the TOCC SDT in developing additional questionnaires that consider BES system response to a variety of cyber-attacks levied against the individual Control Centers. These subsequent questionnaires will require that detailed analysis be performed to identify if a specific cyber event scenario will result in instability, uncontrolled separation, or Cascading that adversely impact the reliability of the BES. The analysis may require that steady-state, dynamic stability and/or transient stability studies be performed.

For the purpose of this field test, a cyber event scenario will be classified as an event during which a BES Cyber Asset is rendered unavailable, degraded or misused. The TOCC SDT will confer with (1) cyber security subject matter experts and (2) power flow analysis subject matter experts during scenario development to ensure that cyber events included in defined scenarios are realistic and will yield informative and actionable simulation results. The scenarios developed are intended to represent worst-case scenarios in order to demonstrate the worst-case impact to the BES. As such, scenarios will likely be beyond the N-1 and extreme events required under the TPL standards. Care will be taken to ensure that the selected scenarios are not redundant with any of the existing CIP-002 criteria that would elevate BES Cyber Assets to high impact.

A successful Field Test will allow the SDT to advance to the industry a revision to Criterion 2.12, with sufficient technical justification, within a new version of NERC Reliability Standard CIP-002. The SDT will propose a bright line for IRC 2.12 based on data collected from field test participants such that there is a high level of confidence that a compromised BES Cyber Asset classified as low impact will not result in instability, uncontrolled separation, or Cascading that adversely impacts the reliability of the BES.

Implementation Schedule and Periodic Updates

Kick off the Field Test in January 2022. Periodic updates will be provided to the RSTC, as necessary, but no later than six months after the Field Test initiates.

DATE	ACTIVITIES	RETURN DATE
December 1, 2021	Confirm field test participants with input from RSTC	December 31, 2021
January 10, 2022	Send initial questionnaire	February 4, 2022
February 7, 2022	Analysis of responses to initial questionnaire	March 4, 2022
March 7, 2022	Send second questionnaire, if necessary*	April 1, 2022
April 4, 2022	Analysis of responses to second questionnaire	April 29, 2022
May 2, 2022	Prepare interim report on analysis	May 27, 2022
June 2022	Provide interim report or update on field test progress to RSTC	N/A
July 11, 2022	Send third questionnaire, if necessary*	August 5, 2022
August 8, 2022	Analysis of responses to third questionnaire	September 2, 2022
September 6, 2022	Send fourth questionnaire, if necessary*	September 30, 2022
October 3, 2022	Analysis of responses to fourth questionnaire	October 28, 2022
October 31, 2022	Prepare final report on analysis and findings	November 18, 2022
December 2022	Provide report on field test findings to RSTC	N/A
December 16, 2022	Post final report and results	N/A
January 2023	Start drafting revisions to CIP-002 based on field test	N/A

*The implementation schedule provides a timeline that includes four questionnaires, but the SDT may be able to complete its analysis and findings with fewer than four, depending on the data received. In that case, the schedule would be revised and the timeline shortened.

Early Withdrawal from the TOCC Field Test

Any participating TOP or TO may withdraw from the TOCC Field Test upon notification to Jordan Mallory. This will effectively terminate the waiver of compliance for participating TOs.

Attachment A

TOCC Configuration and Relationship with Associated TOP

Per the ROP, every BES transmission asset is required to have a registered TO and registered TOP. In many cases the registered TO has acquired a registered TOP for their BES assets via a contract or agreement. There are several different Operating Protocols and system configurations between the TOP and TO supervisory control and data acquisition (SCADA) systems and the BES.

A Control Center is currently defined as "One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities[1] at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations." (A Facility is defined as a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

Further, a TOP is defined as "The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission Facilities."

The purpose of this Attachment is to define a Technical Rationale for determining if the TO's cyber system and associated Operating Protocols are used to perform the functional obligations of the Transmission Operator under Criterion 2.12.

For the evaluation of evaluation of Attachment A examples, the TO Dispatch Center has the following characteristics:

- TO organization is not affiliated with the TOP organization
- TO organization has a contract or agreement with the TOP organization to be their NERC registered TOP for the TO owned BES assets.
- TO organization is not required to have NERC-certified System Operators
- TO Dispatch Center location contains Cyber Assets that are connected (hardwired, routable or serial) to Cyber assets located at two or more BES locations (substations or plant switchyards).

The term "TO dispatcher" used in the Attachment A examples is a generic term for personnel located at TO Dispatch Center that have access to Cyber Assets that are connected (hardwired, routable or serial) to Cyber assets located at two or more BES locations (substations or plant switchyards). These personnel could be, but not limited to the following job titles

- Transmission Dispatcher
- Distribution Dispatcher
- Power dispatchers

[1] (A Facility is defined as set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)

- Dispatcher
- Crew / work dispatcher
- Switching Supervisor

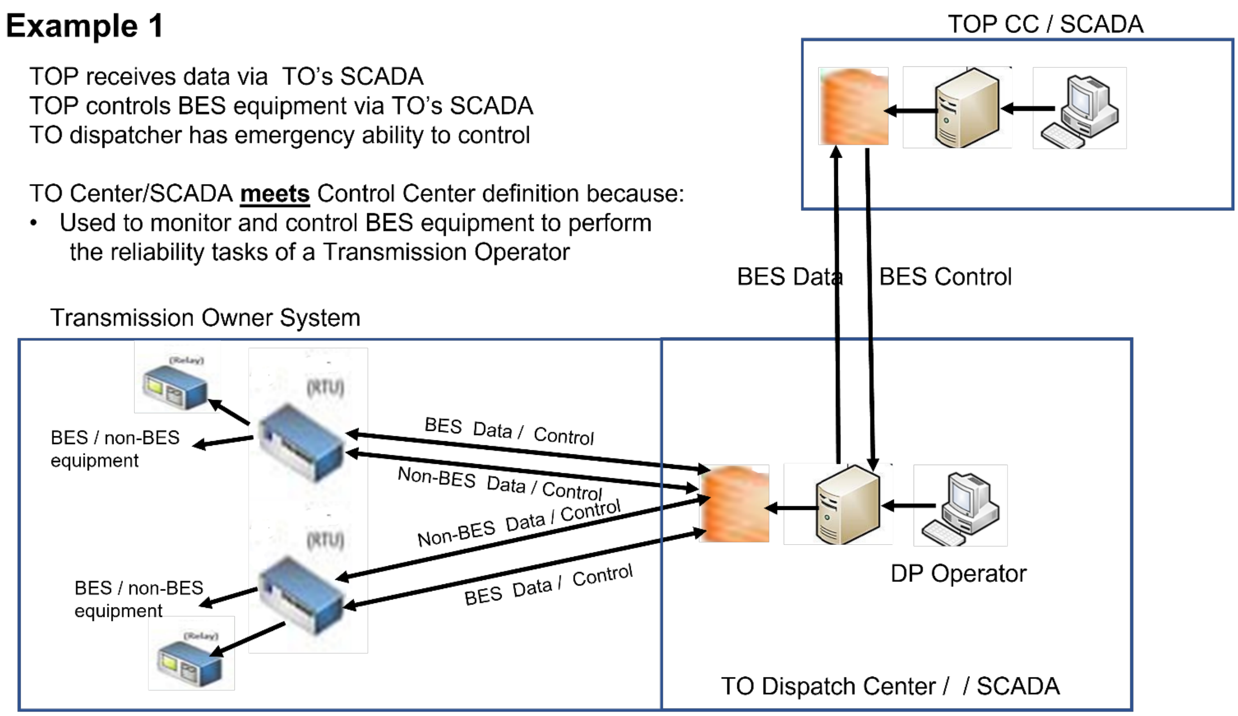
Based on these characteristics, the TO Dispatch Center should have the TOP – TO functional relationship per the Attachment A examples. The evaluation should be used to determine if the TO Dispatch Center meets the definition of a Control Center used to perform the functional obligations of the Transmission Operator under Criterion 2.12.

Example 1:

TOP receives data via TO's SCADA
TOP controls BES equipment via TO's SCADA
TO dispatcher has emergency ability to control

TO Center/SCADA **meets** Control Center definition because:

- Used to monitor and control BES equipment to perform the reliability tasks of a TOP

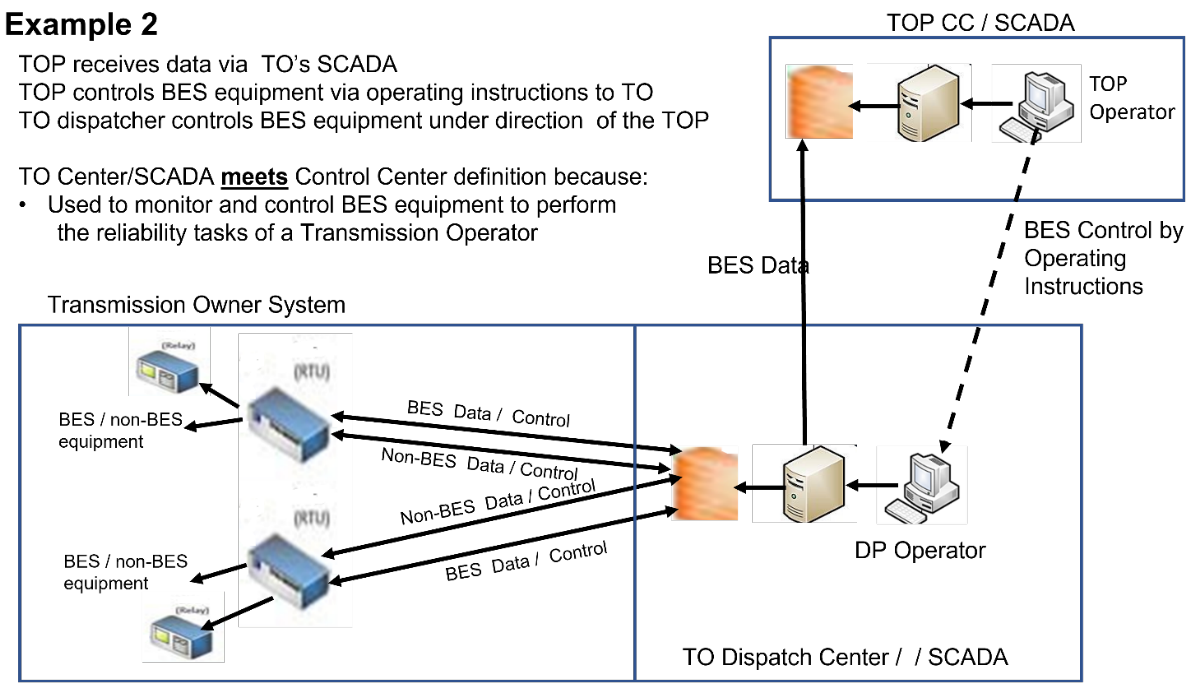


Example 2:

TOP receives data via TO's SCADA
TOP controls BES equipment via operating instructions to TO
TO dispatcher controls BES equipment under direction of the TOP

TO Center/SCADA **meets** Control Center definition because:

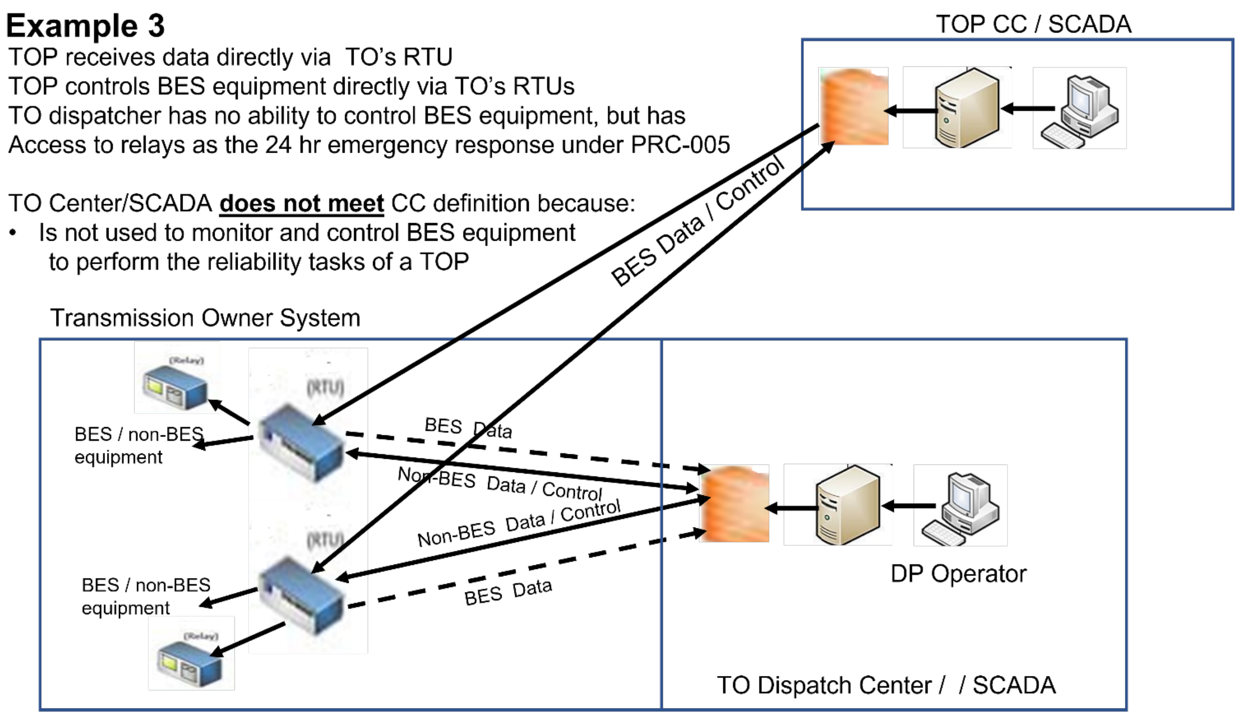
- Used to monitor and control BES equipment to perform the reliability tasks of a TOP



Example 3:
TOP receives data directly via TO's RTU
TOP controls BES equipment directly via TO's RTUs
TO dispatcher has no ability to control BES equipment, but has access to relays as the 24-hr emergency response center under PRC-005

TO Center/SCADA **does not meet** Control Center definition because:

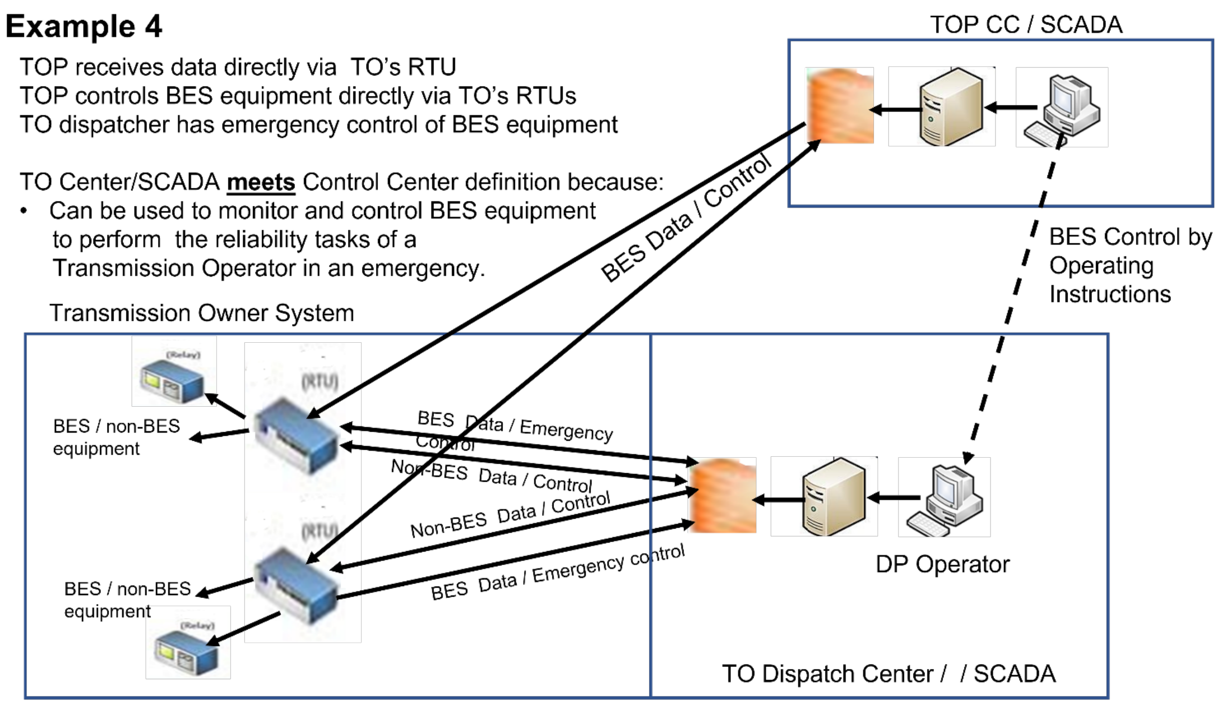
- Is not used to monitor and control BES equipment to perform the reliability tasks of a TOP
- Transmission Operator monitors and controls BES equipment directly via TO's RTU's



Example 4:
TOP receives data directly via TO's RTU
TOP controls BES equipment directly via TO's RTUs
TO dispatcher has emergency control of BES equipment

TO Center/SCADA **meets** Control Center definition because:

- Can be used to monitor and control BES equipment to perform the reliability tasks of a TOP in an emergency.



Attachment B

TOCC Field Test Entry Questionnaire

Please complete the following questions to help us better understand your system.

As a NERC Control Center is applicable to specific configurations, an entity may have no CC, may have one, or could possibly have multiple CC locations. To the extent that an entity has multiple CC locations that control different Facilities, the entity should complete a separate questionnaire for each CC location or clearly delineate between each CC location on the questionnaire as the individual outcomes of the application of Criterion 2.12 could be different.

1. NERC Registration (e.g., RC/BA/TO/TOP/DP/etc.): ______________________________________

2. Do you have a site that is staffed by operating personnel, from which you can remotely operate Facilities at two or more locations?

   ☐ Yes ☐ No

3. Based on the impact to the BES of a cyber event in your footprint, do you believe the site(s) referenced in Question 2 should be low impact, medium impact or high impact? Why?

   ____
   ____
   ____
   ____
   ____
   ____
   ____
   ____
   ____

4. What was the peak load served by your system for the period 1/1/2020 – 10/1/2021, which could be interrupted remotely from the site referenced in Question 2?

   ____

5. What is the total capacity of conventional BES generation Facilities connected to your system, which could be interrupted remotely from the site referenced in Question 2?

   ____

6. What is the total capacity of intermittent (e.g., wind, solar) BES generation Facilities connected to your system, which could be interrupted remotely from the site referenced in Question 2?

   ____

Answer all of the following questions for each location for which the response to Question 2 was "yes".

7. Is there external connectivity to any BES Cyber Asset(s) housed at the site(s) referenced in Question 2? If so, please provide access means for each connection (e.g., dial-up, internet, VPN).

   ☐ Yes ☐ No Access means: ______________________________

8. Do third parties have direct communications access for change management or other managed service provider purposes for the site(s) referenced in Question 2?

   ☐ Yes ☐ No

9. How does your organization conduct its change management activities?
   ____
   ____
   ____
   ____
   ____
   ____
   ____

10. Does your company have supply chain or other internal control protocols in place for the purchase and maintenance of computer systems that are housed at the site(s) referenced in Question 2?

    ☐ Yes ☐ No

For the purpose of responding to the remainder of this questionnaire, a Transmission Line is defined by the protection system(s) that would be used to isolate a fault on a line. Typically, all sources of fault current for a line fault will be interrupted by breakers. Transmission Lines can be single-ended, two-ended, or three-ended. After identifying your Transmission Lines, the NERC definition of BES should be applied to each line to determine if it is a BES Transmission Line. Single-ended, or radial lines, are not typically considered to be BES assets.

Only include Transmission Lines where you have the ability to remotely operate a device to interrupt network flow (through-flow across the line). If you have remote control of multiple devices on a single Transmission Line as defined above, you should only count that line one time in your response. You should still count the line even if another entity controls the remote end of the line.

11. Provide the following information:

	Total number of BES Transmission Lines where you have the ability to remotely operate a device to interrupt network flow on the line.	Total number of BES Transmission Lines where you have the ability to remotely operate a device to interrupt network flow on the line AND another entity has the ability to remotely operate a device to interrupt flow on the same element or a series element.
100 kV to 199 kV		
200 kV to 299 kV		
300 kV to 499 kV		
500 kV and above		

CIP-002 Transmission Owner Control Centers (TOCCs) Field Test Questionnaire

Project 2021-03

Please complete the following questions to help us better understand your system.

As a NERC Control Center is applicable to specific configurations, an entity may have no CC, may have one, or could possibly have multiple CC locations. To the extent that an entity has multiple CC locations that control different Facilities, the entity should complete a separate questionnaire for each CC location or clearly delineate between each CC location on the questionnaire as the individual outcomes of the application of Criterion 2.12 could be different.

1. NERC Registration (e.g., RC/BA/TO/TOP/DP/etc.): ____
2. Do you have a site that is staffed by operating personnel, from which you can remotely operate Facilities at two or more locations?

   ☐ Yes ☐ No

3. Based on the impact to the BES of a cyber event in your footprint, do you believe the site(s) referenced in Question 2 should be low impact, medium impact or high impact? Why?

   ____
   ____
   ____
   ____
   ____
   ____
   ____
   ____
   ____

4. What was the peak load served by your system for the period 1/1/2020 – 10/1/2021, which could be interrupted remotely from the site referenced in Question 2?

   ____

5. What is the total capacity of conventional BES generation Facilities connected to your system, which could be interrupted remotely from the site referenced in Question 2?

   ____

6. What is the total capacity of intermittent (e.g., wind, solar) BES generation Facilities connected to your system, which could be interrupted remotely from the site referenced in Question 2?

   ____

Answer all of the following questions for each location for which the response to Question 2 was "yes".

7. Is there external connectivity to any BES Cyber Asset(s) housed at the site(s) referenced in Question 2? If so, please provide access means for each connection (e.g., dial-up, internet, VPN).

   ☐ Yes ☐ No Access means: ___________________________

8. Do third parties have direct communications access for change management activities associated with BES Cyber Assets or other managed service provider purposes for the site(s) referenced in Question 2?

   ☐ Yes ☐ No

9. How does your organization conduct its change management activities for BES Cyber Assets?

   ____
   ____
   ____
   ____
   ____
   ____
   ____

10. Does your company have supply chain or other internal control protocols in place for the purchase and maintenance of computer systems that are housed at the site(s) referenced in Question 2?

    ☐ Yes ☐ No

For the purpose of responding to the remainder of this questionnaire, a Transmission Line is defined by the protection system(s) that would be used to isolate a fault on a line. Typically, all sources of fault current for a line fault will be interrupted by breakers. Transmission Lines can be single-ended, two-ended, or three-ended. After identifying your Transmission Lines, the NERC definition of BES should be applied to each line to determine if it is a BES Transmission Line. Single-ended, or radial lines, are not typically considered to be BES assets.

Only include Transmission Lines where you have the ability to remotely operate a device to interrupt network flow (through-flow across the line). If you have remote control of multiple devices on a single Transmission Line as defined above, you should only count that line one time in your response. You should still count the line even if another entity controls the remote end of the line.

11. Provide the following information:

	Total number of BES Transmission Lines where you have the ability to remotely operate a device to interrupt network flow on the line.	Total number of BES Transmission Lines where you have the ability to remotely operate a device to interrupt network flow on the line AND another entity has the ability to remotely operate a device to interrupt flow on the same element or a series element.
100 kV to 199 kV		
200 kV to 299 kV		
300 kV to 499 kV		
500 kV and above		

	Q1 Received	Q2 Received	Q2 PF Studies Complete		Need to de
Entity 1		X			Follow up (
Entity 2					
Entity 3	X	X			
Entity 4	X				
Entity 5					
Entity 6	X	X			
Entity 7	X				
Entity 8					
Entity 9	X	X			
Entity 10	X				
Entity 11	X	X			
Entity 12	X	X			
Entity 13	X				
Entity 14	X	X			
Entity 15	X				
Entity 16	X	X			
Entity 17	X	X			
Entity 18	WITHDRAWN	WITHDRAWN	WITHDRAWN		
Entity 19	X	X			
Entity 20	X	X			
Entity 21	X	X			
Entity 22	X	X			

etermine if they plan to participate in the Field Test. If so, responses are required.

		Entity 1	Entity 3	Entity 4	Entity 6	Entity 7	Entity 9	Entity 10	Entity 11
		0	5750	2950	0	250	9000	750	1750
Q1.1	NERC Registration		TO, GO, DP, TP	TO/TOP/DP/GO/GOP/TP	TO	BA, PA/PC, TO, TOP	Unknown	GO/GOP/TO	DP/GO/GOP/RP/TO/TP
Q1.2	Do you have a site that is staffed by operating personnel, from which you can remotely operate Facilities at two or more locations?		Yes	Yes	No	Yes	Yes	No	Yes
Q1.3	Based on the impact to the BES of a cyber event in your footprint, do you believe the site(s) referenced in Question 2 should be low impact, medium impact or high impact? Why?		Our site should be classified as a low impact. All Facilities this site has control of are load serving with no frequency or voltage control ability. There are no IROL, SOL, or RAS associated with our Facilities. All steady state and transient state studies show no stability impacts.	Entity 4 believes its Control Centers should be low impact because Entity 4 is a vertically integrated utility that operates a radial system. None of Entity 4's transmissions lines are marketed within the OASIS system or within its RC. Entity 4's system does not contain major paths, no Blackstart resources, no IROLs. As a net importer of energy, energy that is delivered into Entity 4's system directly serves its customers. Entity 4 does not provide the greater BES with energy support services. It is our assesssment that Entity 4's system is akin to a "meter".	Entity 6 has no Control Center and has no operational control over its BES assets, or Cyber system assets.	Entity 7 has a 138kV ring bus and another 138kV ring bus under construction. Both of these interconnections loop in a 138kV line with two external tie lines. The neighboring TOP operates the middle breaker, and these should be low impact. If a cyber-attack occurs on Entity 7's EMS and the bad actor opens all of our transmission breakers, it would blackout our entire system. However this would have minimal impact on the rest of the BES. The immediate issue would be a temporary increase to our neighboring TOP's ACE until their AGC can	According to CIP-002-5.1a Entity 9 cannot have a widespread event.	Low Impact. The master plant/control center is a 160MW generation facility with an adjacent 161 kV switchyard that has two lines. The remote plant is a 52 MW generation facility with an adjacent 161 kV switchyard that has three lines. The master plant is staffed 24/7 by operations personnel and M-F from 0600-1630 by maintenance personnel. The remote plant is staffed M-F 0600-1630 by maintenance personnel. The switchyard breakers for the master plant are operated locally from the main board in the control room. The switchyard breakers for the remote plant	Low impact. Based on the proposed bright line Criterion 2.12 from CIP-002-6, Entity 11 would have a weighted value of 1750, which is only 29% of the weighted value of 6000 to be considered medium impact. Below are examples that further illustrate the capability and size of Entity 11 that suggest a low impact rating is adequate. 1. Entity 11's control center does not have the capability to manipulate or interrupt any BES generation. 2. Entity 11's control center does have the capability to electrically isolate a portion
Q1.4	What was the peak load served by your system for the period 1/1/2020-10/1/2021, which could be interrupted remotely from the site referenced in Question 2?		Modeling and loading data for 2021 is not ready at this time. Most recent data is 1/1/20 – 2/28/21. The total peak load for Entity 3 is 641 MW. Excluding radial loads served from other Facilities outside of the Entity 3 system, the total peak load is 441.3 MW. The largest single load served by Entity 3 Facilities that can be interrupted is 20.6 MW.	598.02 MW	0	118 MW	447.5 MW	The 3 transmission line interconnections are limited to 800A each.	92.7 MW
Q1.5	What is the total capacity of conventional BES generation Facilities connected to your system, which could be interrupted remotely from the site referenced in Question 2?		0	147.8 MW	0	0	160 MW	52MW	0
Q1.6	What is the total capacity of intermittent (e.g., wind, solar) BES generation Facilities connected to your system, which could be interrupted remotely from the site referenced in Question 2?		0	0	0	0	0	There are no intermittent BES generation facilities connected, 0MW.	0
Q1.7a	Is there external connectivity to any BES Cyber Asset(s) housed at the site(s) referenced in Question 2?		Yes	Yes	N/A	No	Yes	Yes	Yes
Q1.7b	If so, please provide access means for each connection (e.g., dial-up, internet, VPN).		1) Firewall secured connection to Vendor that must be initiated by Entity 3 utilizing a jump host. No control ability can be iniated by Vendor with out electronic authorization by Entity 3 personnel who are physically monitoring and authorizing access. Vendor provides background checks, access authorization updates, and all	VPN	N/A	N/A	NONE LISTED	SCADA VPN to the remote plant, it's an isolated system with no external connections.	Private firewalled LAN network
Q1.8	Do third parties have direct communications access for change management activities associated with BES Cyber Assets or other managed service provider purposes for the site(s) referenced in Question 2?		No	Yes	N/A	No	No	No	No
Q1.9	How does your organization conduct its change management activities for BES Cyber Assets?		A combination of change logs and documentation for tracking configuration changes. Hardware changes are reviewed for impacts to existing systems and security risks, installation planning, implementation and testing, and all final project or system documentation is filed.	Entity 4 utilizes in-house staff as well as third party service providers to perform change management activities on its BES Cyber Assets. Per our internal policies, BES Cyber Systems are patched twice a year, and patches for associated assets are maintained every 30-35 days.	N/A	There are two ways Entity 7 accomplishes this. For minor issues such as installing a patch, the EMS manufacturer would access a secure site protected with two way access; and for major updates such as an EMS upgrade, we will mail the EMS manufacturer the server for them to install it.	Change requests are submitted through a management system and authorization is tracked within the system.	Settings, configurations, and etc. are periodically reviewed by subject matter experts (SMEs) against various criteria. Proposed changes by SMEs are then are reviewed by applicable stakeholders. Changes are approved or disapproved by the appropriate level of management. Implementation of approved changes are coordinated with	Entity 11 has an informal/internal control management as resources are restricted to authorized individuals and physical and/or logical restrictions are in place to prevent unauthorized change.
Q1.10	Does your company have supply chain or other internal control protocols in place for the purchase and maintenance of computer systems that are housed at the site(s) referenced in Question 2?		Yes	Yes	N/A	No	Yes	Yes	No
Q1.11a	100kV-199kV: BES T-lines where you have the ability to interrupt network flow on the line		23	9	0	1	36	3	7
Q1.11b	100kV-199kV: BES T-lines where you have the ability to interrupt network flow on the line AND another entity can remotely operate a device to interrupt flow on the same line		10	0	0	1	7	0	2
Q1.11c	200kV-299kV: BES T-lines where you have the ability to interrupt network flow on the line		0	1	0	0	0	0	0
Q1.11d	200kV-299kV: BES T-lines where you have the ability to interrupt network flow on the line AND another entity can remotely operate a device to interrupt flow on the same line		0	0	0	0	0	0	0
Q1.11e	300kV-499kV: BES T-lines where you have the ability to interrupt network flow on the line		0	0	0	0	0	0	0
Q1.11f	300kV-499kV: BES T-lines where you have the ability to interrupt network flow on the line AND another entity can remotely operate a device to interrupt flow on the same line		0	0	0	0	0	0	0
Q1.11g	500kV+: BES T-lines where you have the ability to interrupt network flow on the line		0	0	0	0	0	0	0
Q1.11h	500kV+: BES T-lines where you have the ability to interrupt network flow on the line AND another entity can remotely operate a device to interrupt flow on the same line		0	0	0	0	0	0	0
Q1.12	Other Comments:								
Q2.0	Do you have a site that is staffed by operating personnel, from which you can remotely operate BES Transmission Elements at two or more locations?	Yes	Yes		No		Yes		Yes
Q2.1	How many Bulk Electric System (BES) breakers do you have the capability[1] to operate from this site via SCADA, including any breakers that you would only operate with authority[2] from another entity?	19	(36) 115kV Breakers		0		90+		ENTITY 11 has a site staffed with operating personnel that can remotely open/close 18 BES breakers via SCADA.
Q2.2	How many BES switches do you have the capability to operate from this site via SCADA, including any switches that you would only operate with authority from another entity?	9	(7) 115kV Line Circuit Switchers. The line circuit switchers do not have protection systems associated with them but they do have load make/break capability.		0		2		ENTITY 11 does not own any BES switches that can be operated via SCADA.
Q2.3a	Aside from your capability to operate devices from this site via SCADA, do you require authorization from another entity prior to operating any device?	Yes					No, ENTITY 9 does not require authorizatio to operate the remote devices.		
Q2.3b	Do you have the capability to operate any devices via SCADA in an emergency independent of your authorizing entity?	Yes					N/A, ENTITY 9 does not require authorization		
Q2.3c	Please describe your capability and authority with respect to operation of your electrical devices.	ENTITY 1 only has authority to open a Transmission Breaker during an Transmission System emergency to prevent loss of Life of Property.	Authorization from our TOP is required prior to operating any BES devices. Our agreement with our TOP does provide us the authority to operate our BES devices in emergency. There is capability to operate the devices listed in questions 1 and 2 in an emergency independent of our authorizing TOP. We are a TO and not a TOP, therefore all authority for the operation of BES devices belongs to our TOP. Execution of control is performed by our operational personnel and our systems after receiving authorization from our TOP pursuant to our TOP agreement.		ENTITY 6 does not have the capability to operate any devices via SCADA due to an emergency or any other contingency		ENTITY 9 operates under the authority of TOP, for planned outages ENTITY 9 must submit requests in advance for approval from TOP.		ENTITY 11 requires authorization from its TOP prior to operating BES breakers. The authorization requires a minimum of 15 days notice. The request is linked to the Reliability Coordinators CROW and reviewed. The request is then either approved or rescheduled based on current and anticipated system conditions. On the day of the operations, ENTITY 11 notifies our TOP of the intent to begin and when operations have been completed. ENTITY 11's TOP notifies other adjacent TOP's prior to the execution of any operations.
Q2.4a	Have you adapted your SCADA system at this site to enable/disable the capability to operate any of your BES Transmission Elements?	No	Yes				Yes		Yes
Q2.4b	If so, did your enabling/disabling occur via a physical disconnection (visible open/air gap) or via software? What actions would be required to restore SCADA capability?		Control can be disabled via the following methods: • Control configuration can be removed from SCADA for any device • Communications can be disconnected from SCADA to the field (air gap) • Separate of our control center, at each substation, we do have "SCADA Disable" switches for each IED (Inteligent Electronic Device) that controls an individual breaker or circuit switcher that when the SCADA Disable is opened will not allow remotely		No		This can be done both locally via switch and remotely by another switch connected remotely. These are then marked by tag locally and electronically on the SCADA system. Those tags need to be removed prior to restoring functionality.		The capability to operate BES breakers is currently enabled. Disabling it would require a settings change in the SCADA software.
Q2.5	Does another entity have the capability to fully isolate your BES Transmission Elements from the BES via their own SCADA systems that do not rely on cyber systems located at this site?	No	Yes		No?		No		Yes
Q2.6a	Have your BES Transmission Elements ever intentionally or unintentionally been cut off from the BES?	No	No		No?		No		No
Q2.6b	If yes, describe any resulting impacts to the remaining BES.						We have never lost all of our BES connections to the larger system.		
Q2.7a	Does any other entity have the capability to operate your BES Transmission Elements[1] via their own SCADA system?	Yes	No		Yes		No		No
Q2.7b	If yes, must that entity rely on any cyber asset associated at this site such as, but not limited to, ICCP?	Yes			Yes				
Q2.8a	Are you required to provide data from your BES Cyber Systems (BCS) to Transmission Operators (TOP) or Reliability Coordinators (RC) per IRO-010 and TOP-003, as necessary for those entities to perform their Operational Planning Analysis, Real-time monitoring, and Real-time Assessments?	Yes	Yes		No		Yes		Yes
Q2.8b	If so, describe the impact to those entities if your data link to that entity were to go down. Explain any mitigating actions that you would take until your data link could be restored. Please provide the date and time, along with a description of impacts to any TOP/RC, for any past event in which your data link to that entity went down in the past five years. Some entities may have considered loss of ICCP alone (covered under CIP-012) and other entities may have considered it as loss of ICCP and	If the TOP lost communication with our system, we can still perform the switching needed while updating the TOP with their permission.	Yes. The impact is minimal. Currently should that data link go down we notify our TOP of the loss of link and then move to phone based communications with the TOP to update them should an event occur on our system that operates a device or causes a suddenly loss of load. Our TOP has visibility of flows into and out of our system independent of the data we provide so ultimately our data only offeres more granular details of how energy is flowing in our system or what devices are operating to shift flows. The data link itself does go down momentarily every time we or our TOP perform database changes on it. Our TOP operators have indicated to us they do not required notification unless we anticipate an extended outage (minutes or hours down verses less than 1 minute). The longest outage we have experienced started the evening of September 15, 2020 and was due to issues with AT&T hardware. It impacted some other entities as well. This disruption lasted approximately 3 days.				Currently we share our data over an ICCP link with our BA/TOP. If the link is lost we maintain communcation with them by phone until service is restored. They typically call and check on any electrical elements that they need to know the status of.		ENTITY 11 has a data link to its TOP that is required for the TOP to perform Operational Planning Analysis, Real-time monitoring, and Real-time Assessments. Loss of the data link to the TOP would prevent them from performing these duties. NOTE 1: The TOP data link does not reside in the ENTITY 11 Control Center. Mitigation: The loss of the data link would not affect ENTITY 11's ability to gather data to our Control Center. ENTITY 11 could mitigate the loss of the TOP data link by providing updated semi-realtime data to the TOP verbally over the phone or through a spreadsheet. This would provide the TOP with ENTITY 11's most recent data values on a semi-periodic basis as needed by the TOP. This data could be manually entered by TOP staff into their SCADA system to overwrite the non-renewed data from the down
Q2.9a	Can protective relays and/or metering equipment be remotely accessed by a BES Cyber System located at your site?	No	Yes		No		Yes		No
Q2.9b	What level of access (i.e., event and fault data only and/or ability to change relay settings and metering configuration)?		Our procedures is to not perform changes this way or to pull event data this way but it is possible if a user has the elevated permissions and the knowledge of how to access the cyber asset that could do this. A user could gather event data and/or make settings changes to relays or meters.				Currently the settings can be changed as we are still installing this functionality at all our sites. The plan is to restrict this access to only event/fault data before finishing the rollout.		
Q2.10a	Do you have a contingency plan for loss/interruption of BES Cyber System(s) located at your site?	Yes	No		Yes		Yes		Yes
Q2.10b	At a high level, what does it cover?	ENTITY 1 will monitor the BES and notify the TOP of changes and alarms. For loss of ENTITY 1 SCADA, we will cordinate with TOP and determine if physical staffing substations is needed.	We do not have a documented contingency plan for loss/interruption of BES Cyber System(s). We do however have an understanding that should any of our BES Cyber Systems become unavailable or compromized we communicate directly with our TOP the current status. At their direction, in the absolute worst case, we would station personnel at substations to perform local operation of devices and report back loading information until such time the BES Cyber System impacted was restored to		Identification, Incident handling/response, containment, coordination, restoration, and reporting		All SCADA systems are fully redundant from a physical perspective as well as being Virtual Servers which can be replicated quickly if needed due to a failure event.		In the event of a loss/interruption of BES Cyber Systems(s), ENTITY 11's methods for restoration include but are not limited to: • Remove/replace compromised equipment • Restore compromised equipment via: o Backup Software o Saved settings files

Entity 12	Entity 14	Entity 15	Entity 16	Entity 17	Entity 19	Entity 20	Entity 21	Entity 22
2000	1250	0	7450	2000	7000	1000	1000	3250
DP, GO, GOP, RP, TO, TP	GO, GOP, TO, DP	TO	TO/DP/GO/GOP/TOP/TP	GO/GOP/TO/TP/DP	TO, TOP, TP, GO, GOP, and DP	TO/DP/TP/RP	BA, DP, GO, GOP, RP, TO, TOP, TP	DP, GO, GOP, RP, TO, TP
Yes	Yes	No	Yes	Yes	Yes	Yes	Yes	Yes
Low Impact – Entity 12 BES facilities directly serve only Entity 12's load. Entity 12's load is relatively small, approximately 71 MW that is under our control, spread across many 100's of square miles of rural territory. The nature of the load is primarily residential with few industrial or commercial loads, and none that would be deemed critical. Entity 12's system is totally enveloped within another Entity's system. We have no IROL's, Nuclear plant station service, blackstart resources or cranking paths that would elevate Entity 12's system to a higher impact status. Entity 12's future	Low Impact due to the nature and characteristics of our transmission system. Entity 14's transmission loop primarily exists to provide electrical service redundancy to the citizens and businesses within our electrical service territory. An interruption within our transmission system only affects Entity 14 locally and will not adversely impact the BES. Entity 14's transmission loop is a downstream, sectionalized feed off the main BES transmission network. The BES does not depend on Entity 14's transmission loop to be operational to maintain BES grid reliability. Entity 14 has no individual	Entity 15 has one site that should be considered LOW IMPACT. The controls for the TO lines are not digitally controlled. The three breakers in the switchyard are controlled with analogue switches that are operated manually by the Operators. No digital controls are used. Protective relays use the analogue outputs to operate the relays in the yard. Other Entities are the TO/TOP for these lines. No example from Appendix A fit the criteria for this site.	It is believed that Entity 16's Control Center and its Backup Control Center should be low impact. The Entity 16 115kV system was designed and operated to distribute a different entity's power from Points of Delivery to Entity 16's local customers. Overall, Entity 16's risk of significant impact to the BES is minimal and would likely be similar to what is experienced during a car-pole accident. In addition, the minimal risk is confined to the Entity 16 customers as Entity 16 does not provide transmission service and power is not scheduled over Entity 16 facilities. Entity 16 can only operate	The site referenced in question 2 is a distribution center that that controls facilities that have been identified as low impact and serve our native load. Our facilities are not located on commercially viable paths, are not critical to the operation of the overall BES; and the loss of any, or all facilities will not result in a BES event that will impact our neighbors. Our native load is approximately 70 MWs, and our transmission system is geographically located in the extreme NE part of Washington State. Our transmission lines only extend 58 miles, and we serve roughly 10,000	Low Impact based on the size, location and load profile. Entity 19's control center does not have the ability to interrupt any BES generation facilities. Entity 19's Transmission facilities have a highest rated voltage of 138KV and under normal system conditions are used primarily to serve distribution load. Entity 19's Transmission system can provide support during outage situation on the external system.	We believe Entity 20 should continue to be deemed low impact due to the reasons below: 1. Entity 20 has only 12.4 miles of BES transmission with around ~300 MVA of transmission capacity served by this 161kV loop. Our BES lines are used to supply our 69kV Sub-transmission system for load distribution to the city, which has a peak load of around 100 MW. Our BES lines complete a 161kV loop with another entity around the metro area.	Low Impact. Entity 21 owns and operates approximately 33 miles of 161kV transmission lines and a single BES generating unit with generating capacity of 149 net MWs under normal operating conditions. We own three substation containing BES assets and have two interconnections to neighboring systems. We do not have any SOL exceedances identified on the BES as a result of multiple contingency conditions and neighboring systems and/or the RC would be able to perform Real-time Assessments absent our ability to monitor our system. As CIP-002-5.1 is currently	Entity 22's control center is low impact as summarized by the following discussion and key points. Entity 22 is a small municipal utility exclusively for the City. The service terriory is approxmatley 8 by 10 miles. The City owns and operates 1 small coal fired power plant, 2 small gas turbines, 34 miles of 115kV transmission line, 9 substations, and the distribution system. The utility is totally surrounded by and exclusively interconnected to another utility. Entity 22 has contracted another utility to perform Transmission Operator (TOP) functions. Entity 22 does not act independently from the
71.3 MW	161 MW	N/A	1300 MW	During 1/1/2020 to 10/1/2021 period we had a peak load of 142 MWs this includes an industrial customer that ceased operation in July of 2020. Our peak customer load is approximately 70 MWs, winter peaking.	557 MW	104 MW	140.93 MW – June 11, 2021 HE 14:00	162 MW (This is the peak load, some of it would not be interrupted remotely, but at the Control Center. Daily peaks run 60-120 MW most of the year.)
196 Nameplate MVA as described on Entity 12's One-Line Diagram	Total BPU generation capacity (Entity 14 Power Plant 2 and 3) - 234.2 MW Local generation capacity (Entity 14 Power Plant 2, location of Control Center) – 154 MW Remote from Control Center generation capacity (Entity 14 Power Plant 3) – 80.2 MW	N/A	Entity 16 has one Hydro plant. Its average megawatts is 29.5 (Max Peak of 100MW). It is a water-limited hydro plant.	Conventional Generation, as we understand it, does not include non-dispatchable hydro generation such as run-of-the-river facilities. For the benefit of of the field test, we do have a 90 MW nameplate run-of-the-river plant that has an average output of approximately 50 MWs, that is connected to our system and through SCADA via the switchyard.	0	0	149 MW net – 161 MW gross	168 MW (However, only 50 to 90 MW is online 95% of the time.)
0	N/A	N/A	Entity 16 does not have any intermittent BES Generation Facilities.	We do not have intermittent resouces on our system.	0	0	0 MW – We do not have any intermittent BES generation Facilities connected to our system.	0
Yes	Yes	No	Yes	No	Yes	Yes	Yes	Yes
Designated corporate workstations have remote desktop protocol (RDP) access to jump host workstations in a restricted DMZ network. The jump host workstations require two factor authentication. Once authenticated to the jump host workstations, depending on the destination device, remote desktop or VNC can be used to access	Serial, Non-Routable Protocol (TG 8979)		VPN		VPN	Dark fiber owned and operated by Entity 20	Entity exchanges real-time reliability and operating data with its RC's Primary and Backup Control Centers using ICCP. RC-owned Cisco routers connected to the SCADA master LAN through Cisco ASA firewalls are used for the RC ICCP data connections. These Cisco routers carry the encrypted ICCP data via dedicated, high speed, leased	TCP/IP connectivity if firewall explicitly allows it from Corporate network, on a per-port (tcp port) basis.
No	No	No	No	No	No	No	No	No
Notifications are sent to stakeholders before and after the patching. Patches are applied to secondary workstations and servers first. Unless a negative or unexpected outcome occurs from these patches, the primary systems are patched after. Digital signatures or hash values are used to verify the integrity of the OS and third-party	Entity 14 internally evaluates the proposed change by discussing the change with internal and external SME's. For transmission system components, Entity 14 utilizes trusted, well-known vendors for new equipment and uses equipment OEMs (when possible) for upgrades. Purchasing approval is granted by the CIP Senior Manager	Currently, there are no cyber/digital controllers for these systems.	Entity 16 conducts weekly change management meetings to review any change requests for BES Cyber Assets following the requirements of CIP-010-3. The change management review process includes but is not limited to reviewing the CIP-005 and CIP-007 cyber security controls that could be impacted by the change, software	We have implemented change management consistent with medium level impact protections. We have formal processes, require authorization, logging, baselining and auditing, regardless of classified impact level.	Entity 19 maintains a configuration change program that identifies baseline configurations and deviations from the baseline. Changes are approved and documented. Security controls are verified after each change. Systems are continually monitoring for changes.	As a maintenance task and/or break-fix tasks come up, staff communciate with each other on what needs to be done within the desired timeframe. The potential impact is communicated and discussed with stakeholders and the Control Center staff to make sure it will not impact any tasks they are working on. Then a final communciation is	As an entity with Medium Impact BES Cyber Systems, we conduct all change management activities in accordance with CIP-010-3. Furthermore, Entity 21 has implemented Tripwire change management software to automate many of the processes associated with change management.	Entity 22 only has two system protection engineers. They directly manage, implement, and document changes for BES Cyber Assets at every location. No third party is ever given access to make any changes on assets. In the situation where an equipment manufacturer or other means of support is consulted, Entity 22 will thoroughly review
Yes	Yes. Informal protocols as explained in Question 9.	No	Yes, Entity 16 maintains multiple plans, policies, processes, and procedures in response to CIP-013 governing the purchase, vetting, vendor risk management, and system development lifecycle of hardware, software, and services affecting the operation of Entity 16's BCS Medium-impact controls centers. Entity 16 has further developed internal controls associated with IT and OT change control to ensure that vendor risk assessments and mitigating/compensating controls have been approved/documented prior to the introduction of new - or change to existing - hardware, software, and/or services.	No	Yes	Yes	Yes	No
8	5	0	27	8	28	4	4	13
6	0	0	13	0	22	2	3	5
0	0	0	1	0	0	0	0	0
0	0	0	1	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
0	0	0	0	0	0	0	0	0
*While Entity 12 Currently has the ability to remotely operate devices to interrupt network flow on the lines, we may only do so after authorization from our Transmission Operator. In addition, we are currently negotiating an agreement to transfer this remote operability to the Transmission Operator. This would make the entries in the 100 kV to 199 kV line above "0" with all of the control moving to the Transmission Operator and out of Entity 12's Transmission Owner Control Center, which would then only have control over non-BES 69 kV and below facilities.			(Entity 16 has 115kV BES lines only. It does not provide OATT/transmission service.) (One 230kV line owned by Entity 16's Balancing Authority)					
Yes	Yes		Yes	Yes	Yes	Yes	Yes	Yes
Sixteen (16)	Nineteen (19) breakers, Entity 14 needs authorization from its TOP to operator all breakers. These (19) breakers include: • 6 – Refinery Substation • 8 – Plant 2 Substation • 5 – JM 115 Substation		64	11 breakers	45 ENTITY 19 owned breakers, ENTITY 19 does not have any breakers that can be operated with authority from another entity.	8	13	28 breakers
Zero (0)	0 switches		78	6 switches	7 ENTITY 19 owned switches, ENTITY 19 does not have any switches that can be operated with authority from another entity.	0	0	0 switches
ENTITY 12 coordinates all BES operations with the TOP. Even in an emergency situation, despite having the capability to operate devices, ENTITY 12 will coordinate authorization to operate concurrently or will do so immediately after the fact. ENTITY 12 currently has the capability to operate BES devices (functional authority) while the TOP has the jurisdictional authority to approve or deny those operations through a Transmission Operator agreement. ENTITY 12 was granted, in 2016, an exemption by NERC and SERC to continue to classify the ENTITY 12 control center as	Entity 14 is required to obtain authorization from its TOP prior to operating the above mentioned breakers. Entity 14 doesn't have an agreement to operate these breakers in an emergency situation and would attempt to gain authorization from the TOP prior to operating the breakers.		We do not require authorization from another entity prior to operating any device. We do not have the capability to operate any device via SCADA in an emergency; independent of our authorizing entity. We only have the capability to operate electrical devices inside our own substations and our 115kV lines.	We cannot independently operate any device without authorization from our TOP. We have an agreement with our TOP which gives them complete authority over us for all BES device operations. They do not have direct control over our system, so they must direct us to switch on their behalf. Our agreement allows for us to remove BES equipment "from service in real-time for emergency, urgent maintenance, mitigation or other any other kind of emergency." This further requires us to notify them prior to taking any of these actions, or "without any intentional delay" after the equipment	ENTITY 19 does not have any devices that require authorization to operate. ENTITY 19 can independtly operate any devices without outside authorization. ENTITY 19 TSOs will coordinate with external entities when switching out ENTITY 19 equipement to confirm impact won't hinder the over reliability of the BES.	We have the cabability to operate all BES breakers in an emergency but all other operations must be approved by our entity's TOP, who has ultimate authority.	No – All devices that can be operated via SCADA are wholly owned and operated by Entity 21. Our System Operators do not need authorization from any other entity to take action and do not have the capability to operate any devices not located on our system.	The small Entity responding to this questionnarie is a registered Transmission Owner who has contracted with a NERC Certified Transmission Operator (TOP). Actual capability to operate devices via SCADA resides with the Entity, but authority resides with the TOP. Per contract the Entity can open BES transmission breakers in an emergency only. All other BES activities and operations must be authorized by the TOP in advance and coordinated with the TOP real time.
No	No		Yes	No	No	No	No	No
ENTITY 12 currently has the capability to operate BES devices (functional authority) while the TOP has the jurisdictional authority to approve or deny those operations through a Transmission Operator agreement. ENTITY 12 was granted, in 2016, an exemption by NERC and SERC to continue to classify the ENTITY 12 control center as a low-impact BES Cyber Asset. This exemption has been continued during the course of the CIP-002 TOCC Field Test. ENTITY 12 is currently negotiating an agreement to			Control can be disabled in the following ways: 1. SCADA can disable the control via the SCADA software; 2. Control can be disabled from the subnet gateway by stopping the service on the gateway; 3. Control can be disabled by disconnecting the cable to the cable or relay.					
Yes	Yes. The TOP (from their independent SCADA system) can fully isolate our BES Transmission Elements from the BES via Entity 14's interconnections at East Entity 14 Substation and West Entity 14 Substation.		Yes	No	Yes	Yes	No	Yes. The small Entity is totally surrounded by and exclusively interconnected to another much larger TO/TOP. The TO/TOP could open their end of all tie lines.
No	No		Yes	No	No	Yes	No	No
			We have never been totally isolated from the BES. Under the events of normal operation outages for part of our system being disconnected to the outside BES (source from our BA/TSP) showed no instability or cascading outage events to the remaining BES. The only potential impact is the loss of our local loads.			9/22/18 our neighboring utility had a low side transformer fault that did not clear and caused a series of 161kV and 69kV transmission lines to trip, which ended up blacking out our system. Only two of our breakers operated; however; neighboring lines feeding our system tripped, which resulted in a system wide outage. Load was lost until they isolated the transformer, and re-energized the lines. About a 40 minute system wide outage resulted.		
No	Yes. Three (3) breakers (owned and maintained by Entity 14) at East Entity 14 Substation (Shared Facility) are solely operated by the TOP via their SCADA system. Entity 14 has no SCADA control of these three (3) breakers.		No	No	No	No	No	No
ENTITY 12 currently has the capability to operate BES devices (functional authority) while the TOP has the jurisdictional authority to approve or deny those operations through a Transmission Operator agreement. ENTITY 12 was granted, in 2016, an exemption by NERC and SERC to continue to classify the ENTITY 12 control center as	No							
Yes	No		Yes	Yes	Yes	Yes	Yes	Yes
ENTITY 12 has redundant ICCP connections to the BA/RC from both its SANITIZED and SANITIZED dispatch centers. This ICCP connection is used for real-time data exchange. ENTITY 12 shares status and analog data, including generator breaker status, MW and MVar outputs, network load flows and network breaker statuses with the BA/RC. BA/RC then shares relevant data to the TOP. If ENTITY 12's data link were to go down entirely (both portions of the redundant connection), BA/RC and TOP would monitor the flows through the TOP side of ENTITY 12 interconnections, and request that ENTITY 12 inform them verbally of any change in status on the ENTITY 12 system. In 2020, the ENTITY 12 ICCP link to BA/RC and TOP was taken down during a planned outage to upgrade ENTITY 12's SCADA server hardware. BA/RC and TOP were made aware beforehand and coordinated the required data as described above. TOP monitored flows on the interconnection			If the data link were lost, the Balancing Authority (BA) would still have readings at the points of delivery and be able to operate transmission lines supporting our electrical system. Coordination with the BA for the readings and neighboring entities if warranted. In addition, we would send field personnel to its switching stations for monitoring. We had one incident of loss of ICCP data to its RC/BA on February 26th 2017 from 12:17 to 01:17. The loss was for approximately 60 minutes due to scheduled maintenance from ATT trunk which was not communicated to us. This was reported to the BA/RC real time, and an OE-417 was sent in as required. We were coordinating sending field personnel to sites when the ICCP came back online. No impacts to the interconnection or neighboring entities were reported to us. Last known values were	We have had the data link fail due to a phone system issue outside of our service area, in that case we were in constant contact with our TOP and BA. Our assests are moniotored by our TOP and BA through metering at our perimeter, and our load ranges from about 27 MWs (Summer) to a high of 77 MWs (winter peak) during the year. We don't have a significant impact on our BA or our TOP. Our footprint is small, approximately 60 miles of BES transmission, and our TOP has redundant monitoring in key substations, so the loss of data is inconsequential to the operation of the TOP BES Area. There are no commercial paths through our system. Our system is geographically located in the SANITIZED. The area is very rural, and mostly forested. There is no scheduled BPS flow through our system.	ENTITY 19 provides data to RC and TOP. For a loss of our ICCP data link, changes to our system for outaged lines or buses will be modeled as they change. On 11/17/2021 from 12:43-13:25 ENTITY 19 had a failure of visibility and monitoring equipement through SCADA. Data going to external entities did not update during this time. Both RC and TOP were able to monitor the ENTITY 19 system accurately using State Estimation tools and in the event of an operation on the BES system TOP would have seen it directly impact their system. No issues were noted even though Real Time Data was not updating.	Since all of our tie lines interconnect with our TOP, they have teletry data on their end of the line, therefore if our data is lost, they can still determine flows into our system, total load, etc.. We have not had any major scada outages however, our RC ICCP connection sometimes goes offline during maintenance, thus interrupting this data. RC's State Estimator and RTCA continued to solve for our system.	ENTITY 21 is required to provide data to RC, our Reliablity Coordinator. If the ICCP link between ENTITY 21 and RC were to go down, we take any online generation off control and hold last set point or dispatch generation at the direction of the RC Generation Balancing Authority Operator (if applicable). We would provide necessary data via phone to RC at their request. If the ICCP data link issues are unique to ENTITY 21-RC and not RC's entire footprint, RC would still have the ability to see MVA flow and voltage levels on either end of our system via ICCP from neighboring entities. The only issue(s) ENTITY 21 has had with the ICCP data link within the past 5 years is related to our SCADA upgrade in May 2021 when we cutover to the new system and during routine maintenance and testing of the link. Prior to conducting any routine maintenance or testing, ENTITY 21 SCADA Administrators contact RC directly, inform	The impact would be loss of telemetry, and thus loss of the capability to perform real time assessments. As answered in question 7, there is no control from outside the system, so control and operations would not be affected. The mitigating action, per the Entity's agreement with NERC Certified TOP for TOP services, would be for the Entity to provide the TOP a snapshot of the telemetry on an agreed to interval via email. A redundant data route is in the design and development phase.
Yes	No		No.	Yes	Yes	Yes	No	Yes
Event and Fault data only. Remote access to this data is restricted to a single Engineering workstation.			No, we are unable to change metering configuration remotely from our control center. No, we are unable to change relay settings remotely from our control center.	Event and fault data only on BES systems.	Relays and metering can all be accessed. Settings can be changed for relaying and metering configurations can be adjusted.	Yes, all access levels as long as the local user credentials are entered.		With proper software and cridentials, one has access to relays and metering equipment including the ability to change settings and configurations.
Yes	Yes. Informal.		Yes	Yes	Yes	Yes	Yes	Yes
ENTITY 12 has a manual systems operations procedure for instances where situational awareness tools are unavailable for extended periods. ENTITY 12 has redundant wide-area communications and server infrastructure in two headquarters buildings that provide hot-standy capability. ENTITY 12 performs regular backups of our Windows-based BES Cyber assets, which would use standard recovery procedures for restoration. ENTITY 12 maintains spare equipment for protective relays and field	Entity 14 doesn't have a formal contingency plan for loss/interruption of the BCS at our site. In the event of a loss/interruption of the BCS, Entity 14 would do the following: Entity 14 has the personnel available to staff our substations to achieve localized control of BES Transmission Elements. Given the geographically size of our system, Entity 14 could have these substations staffed within a timely manner. Radio communication between the substation(s) and Entity 14 Power Plant 2 Control Center		Our "Plans for Loss of Control Center Functionality" process states that: in any event the control center is down, and the backup control center is implemented, SCADA will be utilized. If SCADA is not available, we will physically staff important stations in our service area to provide communication (land line, cell phone, 900MHz radio, etc.) to enable the Operating personnel to monitor and control facilities associated with the BES. Depending on the severity/loss or interruption of BES Cyber System the above	Yes, in extreme situations we dispatch operating personnel to perform manual switching via telephone or radio, have a manned 92 MWs powerplant, and we communicate with our TOP and BA via VIOP, POTS, cell phone, or radio for needed data. We only have 3 BES substations, and a switchyard. Geographically, the switchyard is associated with a manned hydro plant and would be staffed by hydro operations or maintenance personnel. One of our substations is located in SANITIZED	ENTITY 19 has an implementation plan to start up our back up control center, same functionality as primary. Plans are in place for Real Time Assessment and Real Time Contingency Analysis to be performed while ENTITY 19 SCADA system is failed.	We would work with our TOP and RC to determine alternate methods of providing any breaker status/load information they may need. We would have people located at key substations relaying data back to the office on an as needed basis. Since our TOP has telemetry at their ends of our tie lines, they would have enough data to calculate our system load.	Entity 21's Control Centers are classified as Medium Impact under CIP-002-5.1 and as such we are responsible to maintain and implement Incident Response & Recovery Plans under CIP-008 and CIP-009 for the BES Cyber Systems (SCADA) that operate and control the BES. At a high level – our plans are consistent with the Requirements of those Standards.	The Entity has installed a human machine interface (HMI) in one of the Entity owned substations on the system. With proper cridentials, the SCADA system can be operated from this site.

CIP-002 Transmission Owner Control Centers (TOCCs) Field Test Questionnaire 2

Project 2021-03

Please complete the following questions to help us better understand your system.

As a NERC Control Center is applicable to specific configurations, an entity may have no CC, may have one, or could possibly have multiple CC locations. To the extent that an entity has multiple CC locations that control different BES Transmission Elements, the entity should complete a separate questionnaire for each CC location or clearly delineate between each CC location on the questionnaire as the individual outcomes of the application of Criterion 2.12 could be different.

Terms explained for the purposes of this questionnaire. (Definitions below apply to this questionnaire and are not necessarily consistent with other ERO approaches.)

- Capability – An entity has the capability to operate if that registered entity's "*control environment*" (Control Center, control room, site where personnel are physically are located to perform duties to conduct the delivery of electricity) has one or more SCADA/PLC/Other electronic control system(s) that can operate electrical equipment such as breakers, switches, or disconnects in either normal or emergency conditions. The entity may have the authority to operate electrical equipment or may require authorization from another entity prior to operating electrical equipment.
- Authority – An entity with the authority to operate electrical equipment has the contractual ability to either operate electrical equipment, or give orders to another entity with the capability (but no authority) to operate electrical equipment.
- Operate – The ability to enable the function of an electrical device or equipment. Examples include opening a breaker or disabling the reclosing function of a breaker. Operations may be performed locally (e.g., at a substation) or remotely (e.g., from a different substation or from a Control Center/control room/site where personnel are physically located to perform tasks as required for the delivery of electricity).

Reference Question 2 from Questionnaire 1:

Do you have a site that is staffed by operating personnel, from which you can remotely operate BES Transmission Elements at two or more locations?

☐ Yes ☐ No

Complete the following for the site(s) referenced in Question 2:

1. How many Bulk Electric System (BES) breakers do you have the capability[1] to operate from this site via SCADA, including any breakers that you would only operate with authority[2] from another entity?

   ____

2. How many BES switches do you have the capability to operate from this site via SCADA, including any switches that you would only operate with authority from another entity?

   ____

3. Aside from your capability to operate devices from this site via SCADA, do you require authorization from another entity prior to operating any device? Do you have the capability to operate any devices via SCADA in an emergency independent of your authorizing entity? Please describe your capability and authority with respect to operation of your electrical devices.

   ____

   ____

   ____

   ____

[1] Reference definition on Page 1 of this document.
[2] Reference definition on Page 1 of this document.

4.
   a. Have you adapted your SCADA system at this site to enable/disable the capability to operate any of your BES Transmission Elements?

      ☐ Yes ☐ No

   b. If so, did your enabling/disabling occur via a physical disconnection (visible open/air gap) or via software? What actions would be required to restore SCADA capability?

____

____

5. Does another entity have the capability to fully isolate your BES Transmission Elements from the BES via their own SCADA systems that do not rely on cyber systems located at this site?

   ☐ Yes ☐ No

6. Have your BES Transmission Elements ever intentionally or unintentionally been cut off from the BES? If yes, describe any resulting impacts to the remaining BES.

   ☐ Yes ☐ No

____

____

____

____

7.
   a. Does any other entity have the capability to operate your BES Transmission Elements[3] via their own SCADA system?

      ☐ Yes ☐ No

   b. If yes, must that entity rely on any cyber asset associated at this site such as, but not limited to, ICCP?

      ☐ Yes ☐ No

[3] This excludes equipment owned by you where you are not able to control, access, nor perform maintenance activity. Such equipment is located within another entity's Facility, and ownership is solely designated to hold you responsible for the cost of maintenance as required and performed by the other entity.

8. Are you required to provide data from your BES Cyber Systems (BCS) to Transmission Operators (TOP) or Reliability Coordinators (RC) per IRO-010 and TOP-003, as necessary for those entities to perform their Operational Planning Analysis, Real-time monitoring, and Real-time Assessments? If so, describe the impact to those entities if your data link to that entity were to go down. Explain any mitigating actions that you would take until your data link could be restored. Please provide the date and time, along with a description of impacts to any TOP/RC, for any past event in which your data link to that entity went down in the past five years.

   ☐ Yes ☐ No

   ____

   ____

   ____

   ____

   ____

9. Can protective relays and/or metering equipment be remotely accessed by a BES Cyber System located at your site? What level of access (i.e., event and fault data only and/or ability to change relay settings and metering configuration)?

   ☐ Yes ☐ No

   ____

10. Do you have a contingency plan for loss/interruption of BES Cyber System(s) located at your site? At a high level, what does it cover?

   ☐ Yes ☐ No

   ____

   ____

   ____

   ____

   ____

11. Please complete the TOCC Definition Power Flow Instruction Document associated with Questionnaire 2 for each site.

Project 2021-03 TOCC Field Test

Questionnaire 2 Power Flow Instruction Document

February 2022

Purpose

The purpose of this document is to provide instructions for entities participating in the Project 2021-03 Standard Drafting Team field test. The goal of the power flow study types in this field test is to evaluate system responses to specific conditions by means of Steady-State power flow runs. These conditions are provided for each study type, beginning on the next page.

Please complete each field requested in this document as it pertains to the study(ies) performed. All requested data should be entered into the tables provided.

Software Used

Detail the name and version of the software used to conduct the power flow study(ies).
Example: PSS/E Version 34.7

Name	
Version #	

Model(s) Used

Models used should include all BPS system elements for your entity's system as well as all BPS system elements of each neighboring system. As a goal of this study is to evaluate potential impacts in the current topology of the system, models are expected to be within the current or near-term timeframe. Consider near-term as 1-3 year models or 1-5 year models, as available. Add rows if more than 1 model is used.
Example: Eastern Interconnection 2020 MMWG series model, year 3

Description of models(s) used	

Case(s) Used

Cases considered for study should include various stressed system conditions. Intentional intrusions into cyber assets causing larger system impacts may align with stressed system conditions to expand the adverse effects on the BPS. Provide a brief description of the case(s) selected for study along with a brief justification on the appropriateness for the case(s) studied. Add rows for additional cases/scenarios studied.
Example: Year 1 and year 2 Summer Peak Load case;
Example: Year 1 and year 2 shoulder (fall season), light load, high wind scenario
Example: Year 1 extreme weather condition

Case Description and justification for use	
Case Description and justification for use	
Case Description and justification for use	

Criteria Used

Criteria used for this field test should be consistent with criteria used by entity's Transmission Planner or Reliability Coordinator for assessing instability, Cascading, and uncontrolled separation. Provide technical justification if other criteria are used. If certain criteria below are not used, please indicate the criteria is not used instead.

Formatting Instructions

Do not delete text or change formatting of tables. Additional rows should be added to each table as needed to accommodate your results. Unused rows may be left empty or can be deleted.

Additional Notes

Each study type will include a field for additional notes. Please use this field to consolidate any additional pertinent material on selection justifications, explanations for items/choices that are not collected in provided tables. These additional notes may also be used to provide clarity on entity-specific system conditions, nuance, or other issues.

Power Flow Study Type 1

Goal: Evaluate system response for violations of thermal and voltage rating criteria in Steady-State.
Area to be evaluated: Entity's own system as well as all neighboring systems.
Study conditions: All breakers/switches that can be operated remotely from the entity's BES Cyber System are simultaneously opened.
Guidance for conducting in power flow program:

1) Create 1 or more sub-areas that comprise all affected buses per study conditions.
2) Lock generator response, tap changes, and shunts.
3) Set monitors on newly created tie-lines from sub-area(s) and neighboring buses.
4) Open newly created tie-lines, solve case.

Criteria Evaluated

Voltage: Provide voltage magnitude threshold as well as voltage deviation threshold.
Example: Voltage Magnitude threshold = 0.95 p.u., Voltage Deviation threshold = 5% change from initial voltage; Rationale based on TP's criteria used in TPL studies

Voltage Criteria	Description	Rationale / Technical Justification
A		
B		

Thermal: Provide ratings used for evaluating thermal overloads. Include % and time. Include additional details of rating such as "ambient-adjusted" specifications if used. Additional rows provided if evaluating multiple ratings.
Example: Rating A = 100% of continuous summer rating, Rating B = 100% of 15 minute emergency rating

Thermal Rating	Description	Rationale / Technical Justification
A		
B		

Total Load Loss: Provide total load loss criteria (if used) for evaluating Cascading or instability.
Example: 500MW total loss of load

Total load loss criteria (MW)	

Total Generation Loss: Provide total generation loss criteria (if used) for evaluating Cascading or instability.
Example: 700MVA total loss of generation

Total generation loss criteria (MVA)	

Transfer Analysis: Describe the method of any transfer analysis conducted.

Q-V Analysis: Describe the method of any Q-V analysis conducted.

Results

Did the case solve after applying the study conditions?

Yes/No?	

What calculation method was used to solve the case?

Power flow calculation method used	

How many iterations did the solution take to solve?

Number of iterations	

Identify any voltage criteria violations on monitored buses. Maintain a record of model bus names and numbers, but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed.

Violation #	Initial Voltage p.u.	Final Voltage p.u.	Delta change % (Final-Initial)/Initial *100
V1			
V2			
V3			
V4			
V5			

Identify any thermal criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed.

Violation #	Rating Violated	Initial Rating MVA	Final Rating MVA	% Above Rating Threshold
T1				
T2				
T3				
T4				
T5				

Total Load Loss (MW)

Total Generation Loss (MVA)

Transfer Analysis Results: Describe notable impact (adverse or beneficial) on neighboring transfer paths/flowgate capabilities. Adjust the table as needed for your results.

Q-V Analysis: Provide the results of any voltage instability identified. Maintain a record of generator/bus used for this analysis but do not provide in this record. In your own records, retain a mapping to the generator/bus #s prepopulated in this record for future reference. Add additional rows and generator/bus #s as needed.

Generator/Bus	Voltage (p.u.)	Actual MVARs
01		
02		

Additional Notes: Provide any additional information that you find as pertinent information to include with your results that do not fit in a table above.

Power Flow Study Type 2

Goal: Evaluate system response for violations of thermal and voltage rating criteria in Steady-State.
Area to be evaluated: Entity's own system as well as all neighboring systems.
Study conditions: All lines and autotransformers which an entity is capable of interrupting through-flow from the entity's BES Cyber System are operated sequentially.
Guidance for conducting in power flow program:

1) Identify all affected lines and autotransformers per the study conditions.
2) Operate each line/auto, beginning with the most heavily loaded line/auto to the least loaded in sequential order. Solve cases between each operation.
3) Allow generator responses, tap changes, and shunts to switch between each sequential operation and Steady-State case solution (i.e. allow system enough time stabilize).
4) Monitor all affected neighboring buses.
5) Open additional lines if criteria thresholds are violated. Note to use appropriate thermal ratings based on loading time for this study (such as a 15 minute emergency rating versus a 2-hour emergency rating)
6) Evaluate total/aggregate number of thresholds violated, total load loss, and total generation loss against Cascading criteria.
7) Continue through all operations.

Criteria Evaluated

Voltage: Provide voltage magnitude threshold as well as voltage deviation threshold.
Example: Voltage Magnitude threshold = 0.95 p.u., Voltage Deviation threshold = 5% change from initial voltage; Rationale based on TP's criteria used in TPL studies

Voltage Criteria	Description	Rationale / Technical Justification
A		
B		

Thermal: Provide ratings used for evaluating thermal overloads. Include % and time. Include additional details of rating such as "ambient-adjusted" specifications if used. Additional rows provided if evaluating multiple ratings.
Example: Rating A = 100% of continuous summer rating, Rating B = 100% of 15 minute emergency rating

Thermal Rating	Description	Rationale / Technical Justification
A		
B		

Total Load Loss: Provide total load loss criteria (if used) for evaluating Cascading or instability.
Example: 500MW total loss of load

Total load loss criteria (MW)	

Total Generation Loss: Provide total generation loss criteria (if used) for evaluating Cascading or instability.
Example: 700MVA total loss of generation

Total generation loss criteria (MVA)	

Cascading: Following an operation per the instructions, provide the conditions for declaring Cascading conditions.
Example: Total number of sequential line/bus operations that occur following an event. Operations may be due to subsequent voltage or thermal violations.

Description of Cascading Criteria	

Transfer Analysis: Describe the method of any transfer analysis conducted.

Q-V Analysis: Describe the method of any Q-V analysis conducted.

Results

Did the case solve for all operations identified in the study conditions?

Yes/No?	

If "No," include additional details per this table:

Number of operations successfully performed before the case failed to solve:	
Number of potential operations remaining:	

What calculation method was used to solve the case?

Power flow calculation method used	

At any point, what was the highest number of iterations the solution took to solve?

Max number of iterations	

Identify any voltage criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed.

Violation #	Initial Voltage p.u.	Final Voltage p.u.	Delta change % (Final-Initial)/Initial *100
V1			
V2			
V3			
V4			

V5			

Identify any thermal criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed.

Violation #	Rating Description	Initial Rating MVA	Final Rating MVA	% Above Rating Threshold
T1				
T2				
T3				
T4				
T5				

Total Load Loss (MW)

Total Generation Loss (MVA)

Cascading: Provide the results of any Cascading condition that occurred.
Example: 5 additional lines opened following the operation of line 7. All 5 sequential trips were due to violation exceedances of thermal rating B. Additional overloads were not investigated following the declaration of a Cascading condition.

Transfer Analysis Results: Describe notable impact (adverse or beneficial) on neighboring transfer paths/flowgate capabilities. Adjust the table as needed for your results.

Q-V Analysis: Provide the results of any voltage instability identified. Maintain a record of generator/bus used for this analysis but do not provide in this record. In your own records, retain a mapping to the generator/bus #s prepopulated in this record for future reference. Add additional rows and generator/bus #s as needed.

Generator/Bus	Voltage (p.u.)	Actual MVARs
01		
02		

Additional Notes: Provide any additional information that you find as pertinent information to include with your results that do not fit in a table above.

Power Flow Study Type 3

Goal: Evaluate system response for violations of thermal and voltage rating criteria in Steady-State.
Area to be evaluated: Entity's own system as well as all neighboring systems.
Study conditions: Study a broad range of system conditions following a wider range of probable Contingencies.
Guidance for conducting in power flow program:

1) Refer to the TPL-001-4 Planning Assessment results for affected system elements in the area to be evaluated.
2) Consider evaluating all extreme events such as those identified for Steady State in Table 1 of TPL-001-4.

Criteria Evaluated

Voltage: Provide voltage magnitude threshold as well as voltage deviation threshold.
Example: Voltage Magnitude threshold = 0.95 p.u., Voltage Deviation threshold = 5% change from initial voltage; Rationale based on TP's criteria used in TPL studies

Voltage Criteria	Description	Rationale / Technical Justification
A		
B		

Thermal: Provide ratings used for evaluating thermal overloads. Include % and time. Include additional details of rating such as "ambient-adjusted" specifications if used. Additional rows provided if evaluating multiple ratings.
Example: Rating A = 100% of continuous summer rating, Rating B = 100% of 15 minute emergency rating

Thermal Rating	Description	Rationale / Technical Justification
A		
B		

Total Load Loss: Provide total load loss criteria (if used) for evaluating Cascading or instability.
Example: 500MW total loss of load

Total load loss criteria (MW)	

Total Generation Loss: Provide total generation loss criteria (if used) for evaluating Cascading or instability.
Example: 700MVA total loss of generation

Total generation loss criteria (MVA)	

Contingencies Evaluated: Provide a description for each Contingency or set of Contingencies run.
Example: Contingency C01 = loss of generator followed by loss of line, all applicable assets

Contingency #	Description
C01	
C02	
C03	
C04	
C05	
C06	
C07	
C08	
C09	
C10	

Results

Did the case solve for all operations identified in the study conditions?

Yes/No?	

If "No," include additional details per this table:

Number of operations successfully performed before the case failed to solve:	
Number of potential operations remaining:	

What calculation method was used to solve the case?

Power flow calculation method used	

At any point, what was the highest number of iterations the solution took to solve?

Max number of iterations	

Identify any voltage criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed. Also include a brief description of the Contingency that caused the violation. Do not use bus/line names in the description; only describe in generic terms what operated.

Example of Contingency Description: Loss of tower line 42; tower had three 230kV circuits

Violation #	Initial Voltage p.u.	Final Voltage p.u.	Delta change % (Final-Initial)/Initial *100	Description of Contingency
V1				
V2				
V3				
V4				
V5				

Identify any thermal criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed. Also include a brief description of the Contingency that caused the violation. Do not use bus/line names in the description; only describe in generic terms what operated.

Violation #	Rating Description	Initial Rating MVA	Final Rating MVA	% Above Rating threshold	Description of Contingency
T1					
T2					
T3					
T4					
T5					

Additional Notes: Provide any additional information that you find as pertinent information to include with your results that do not fit in a table above.

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:	Modifications to CIP-002		
Date Submitted:	10/4/2021		
SAR Requester			
Name:	Latrice Harkness		
Organization:	NERC		
Telephone:	404-446-9728	Email:	latrice.harkness@nerc.net

SAR Type (Check as many as apply)

- ☐ New Standard
- ☒ Revision to Existing Standard
- ☐ Add, Modify or Retire a Glossary Term
- ☐ Withdraw/retire an Existing Standard
- ☐ Imminent Action/ Confidential Issue (SPM Section 10)
- ☐ Variance development or revision
- ☐ Other (Please specify)

Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)

- ☐ Regulatory Initiation
- ☐ Emerging Risk (Reliability Issues Steering Committee) Identified
- ☐ Reliability Standard Development Plan
- ☐ NERC Standing Committee Identified
- ☐ Enhanced Periodic Review Initiated
- ☒ Industry Stakeholder Identified

Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):

The purpose of this project is to ensure that all BES Cyber Systems' associated Cyber Assets are identified for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those Cyber Assets could have on the reliable operation of the BES. Identification and categorization of these Cyber Assets supports appropriate protection against compromises. Without an accurate inventory of associated Cyber Assets, registered entities may fail to deploy appropriate controls to these Cyber Assets, which may lead to misoperation or instability in the BES.

Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):

Electronic Access Control or Monitoring Systems (EACMS), Physical Access Control Systems (PACS), and Protected Cyber Assets (PCAs), if compromised, pose a threat to their associated BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (PCA), or (b) the security control function they perform (EACMS and PACS). This project will ensure the reliable operation of the BES by requiring the identification of these Cyber Assets so that the appropriate controls can be implemented.

Requested information
Project Scope (Define the parameters of the proposed project):
This project will make revisions to CIP-002 to include the identification and categorization of certain Cyber Assets (EACMS, PACS, and PCAs) associated with high and medium impact BES Cyber Systems.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Revise CIP-002 to include the identification of EACMS, PACS, and PCA.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact is unknown at this time. However, a question will be asked during the comment period to ensure cost aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
None.
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):
Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Interchange Coordinator or Interchange Authority, Reliability Coordinator, Transmission Operator, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
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 2016-02, Project 2021-03
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
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	None.

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

Request for Interpretation (RFI)

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 RFI to your ticket. Once submitted, you will receive a confirmation number which you can use to track your request.

Note: an Interpretation cannot be used to change a standard.

Interpretation 2022-INT-01: Request for an Interpretation of CIP-002-5.1a, Requirement R1, for Burns & McDonnell
Date submitted: 10-22-2021
Contact information for person requesting the interpretation:
Name: Terry Brinker
Organization: Burns & McDonnell
Telephone: 219-614-1321
Email: tlbrinker@burnsmcd.com
Identify the standard that needs clarification:
Standard Number (include version number): CIP-002-5.1a, R1
Standard Title: Cyber Security – BES Cyber System Categorization
Identify specifically what requirement needs clarification:
Requirement Number and Text of Requirement: Req. R1: Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: • Clarification needed: Specifically, if system-to-system serial communications between a Transmission Owner's (TO) medium impact Bulk Electric System Cyber System[1] (BCS) connects to a Transmission Operator's (TOP) BCS must any and all converters protect the connection by either enforcing an authentication break or by residing inside a defined Electronic Security Perimeter[2] (ESP) (thereby relying upon the ESP to provide the necessary protections)?

[1] One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.
[2] The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.

• In such cases, is it a pre-requisite that said converters must meet the definition of a Bulk Electric System Cyber Asset[3] (BCA) to justify such protections?
Identify the material impact associated with this interpretation:
Identify the material impact to your organization or others caused by the lack of clarity or an incorrect interpretation of this standard. The material impact caused by the lack of clarity for such communication devices extends the delineation points beyond the defined Electronic Security Perimeters and creates various interpretations. The various interpretations are not just to the CIP Standards, but also the responsibilities and ownership of the reliability tasks found in the NERC Functional Model.

Version History

Version	Date	Owner	Change Tracking
1	April 22, 2011		
1	May 27, 2014	Standards Information Staff	Updated template and email address for submittal.
1	June 28, 2017	Standards Information Staff	Updated template.
2	February 22, 2019	Standards Information Staff	Added instructions to submit via Help Desk
3	February 25, 2020	Standards Information Staff	Updated template.

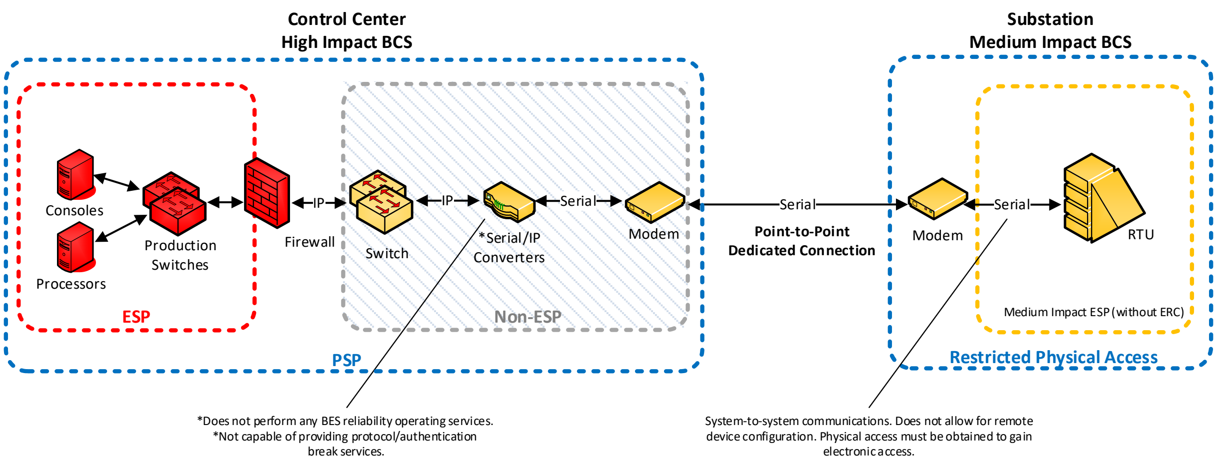
[3] A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would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

Request for Interpretation - CIP-002-5.1a R1

Background

Burns & McDonnell is representing a client that has Internet Protocol (IP) to serial converters (converters) physically located at Control Centers but outside of any defined Electronic Security Perimeters (ESPs). The converters are used as part of the communications network to convert serial traffic from medium impact BES Cyber Systems (BCS) at Transmission substations (without ERC) to IP enabling data communication. The converters also do not perform any BES reliability operating services as found in the Guidance and Technical Basis of CIP-002-5.1a. Burns and McDonnell has confirmed the converters are not technically capable of providing protocol/authentication break services. The client had classified the converters as out of scope under its CIP-002 methodology as falling under the CIP-002-5.1a Applicability Exemption 4.2.3.2. "*Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters*".

A visual depiction of the client's architecture to provide context of the converters in relationship to upstream and downstream BES Cyber Assets and ESPs is depicted per the following network diagram.



The Issue

Our client was told by its Regional Entity (RE) upon review of the converters and their infrastructure that:

> *"Whenever a serially connected BCA (such as an RTU) is accessed through a network via a routable protocol using a protocol converter (such as a <manufacturer specific>), the protocol converter must protect the connection by either enforcing an authentication break or by residing inside a defined ESP (thereby relying upon the ESP to provide the necessary protections). If used, an authentication break must be an interactive process that interrupts the connection and forces the end user to respond to an authentication challenge."*

The RE also indicated the following:

> *"Per CIP-005-5 R1, Part 1.1, all applicable Cyber Assets connected to a network via a routable protocol shall reside within a defined Electronic Security Perimeter (ESP). Applicable Cyber Assets include high and medium impact BES Cyber Systems and their associated Protected Cyber Asset (PCA) (Reference: CIP-005-5 Table R1). Residing within a defined ESP requires that an applicable Cyber Asset's interfaces that communicate via a routable protocol be physically connected to the ESP network.*
> *The <converters> referenced in the <client's> inquiry are serially connected to medium impact BES Cyber Assets. The terminal servers are also connected via a routable protocol to the <client's> Internet Protocol (IP) network. The terminal servers provide protocol conversion, without an authentication break, for the serially connected BES Cyber Assets so these devices may communicate via a routable protocol with other assets located on the IP network. This configuration effectively connects the medium impact BES Cyber Assets to a network via a routable protocol; therefore, they must reside within a defined ESP. Specifically, the interfaces that communicate via a routable protocol (which in this case are attached to the <converters> must be physically connected to a defined ESP network."*

One fundamental issue with RE's position is not distinguishing between Interactive Remote Access (IRA) and system-to-system process communications. As shown in the provided network diagram, the communications between the Control Centers and substations are strictly system-to-system. Any configuration or modification to the application BES Cyber Assets (BCA) requires physical access and the use of a port separate than the serial port.

The client is thereby being asked by its RE to do one of the following:

1) Implement on the converters, an authentication/protocol break service to the serially connected transmissions stations and classify and protect the converters as Electronic Access Control or Monitoring Systems (EACMS) associated with medium impact BES Cyber Systems.
   a. The converters do not have the technical capability to perform any type of "*electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems*". After discussion with the RE, it was agreed EACMS was not an appropriate categorization for the converters due to the technical capability limitation.

2) Move the converters into adjacent high impact ESPs and classify and protect the converters as Protected Cyber Assets associated with high impact BES Cyber Systems.
   a. This approach lowers the client's security posture since moving the converters inside the existing high-impact ESP would then bypass any Electronic Access Points (EAP). The proposed architecture would directly connect the Ethernet port of the converters to the front-end processors (FEP) and no longer be afforded the protections of the EAP. The RE agreed that this was not an ideal solution for the

same reasons. Additionally, the RE's position to classify the converters as PCAs also highlights they do not meet the definition of a BCA.

3) Classify the converters as BCAs associated with the medium impact BES assets where the serially connected BES Cyber Assets reside. This would necessitate defining the network segment in which the converters reside as an ESP and ensuring compliance thereof with CIP-005-5 R1.

    a. In Option 2, the RE states a PCA categorization is acceptable. This statement highlights, and confirms the initial categorization, these Cyber Assets do not meet definition of a BCA based on their function. Additionally, the converters are physically located at the Transmission Operator's (TOP) Control Centers and not at the Transmission Owner's (TO) substations with medium impact BCSs. Such an approach blurs the delineations in the NERC Functional Model between the Functional Entity types of TOP and the TO as each have separate roles and equipment for their respective reliability tasks. In various situations, the TOP and the TO may or may not be the same registered entity and ownership of communication equipment may be split or be owned and managed by a third party.

FERC and NERC have attempted to clarify these types of components with publications. First, NERC provided a lessons learned document that addressed converters in 2015 in a document titled Lesson Learned CIP Version 5 Transition Program - Communications to BES Cyber Systems and BES Cyber Assets. The following are key extracts from the document:

> ***Communications to serially connected BES Cyber Systems.*** *When BES Cyber Systems or BES Cyber Assets were connected using serial data links, the communication networks, including protocol converters and terminal servers, were reviewed to identify risks. Communications were grouped into two categories;*
>
> • *Interactive Remote Access:*
> *The CIP version 5 standard requirements for Interactive Remote Access to BES Cyber Asset do not include serial communications. However, when BES Cyber Systems or BES Cyber Assets are connected using serial data links that provide a way for a user-initiated remote access with a BES Cyber Asset, security risks can arise. Associated communication networks were reviewed to identify these risks. In order to help reduce this risk, while not required to demonstrate compliance, study participants chose to utilize two-factor authentication and access controls, where possible, similar to an Intermediate System.*
>
> • *System-to-system process controls:*
> *The CIP version 5 standard requirements for Interactive Remote Access do not include system-to-system processes using serial communications. However, study participants identified routable connectivity to an asset containing medium impact rating BES Cyber Assets as a possible security risk when there was an IP-to serial conversion between a BES Cyber Asset and an external network.*

> *In order to help reduce this risk, while not required to demonstrate compliance, study participants chose to implement a firewall with strict inbound and outbound access permissions allowing only network traffic documented as essential to the proper functioning of the BES Cyber Asset. Also, study participants provided additional measures in their physical security plan for these types of assets to provide an extra level of protection against unauthorized access. No additional controls were implemented for relay-to-relay communications.*

The client's existing architecture follows this guidance by locating the converters inside a Physical Security Perimeter (PSP) and forcing the routable communications from the converters through an EAP (firewall) with a strict ruleset.

Second, is FERC's Lessons Learned from Commission-Led CIP Reliability Audits from 2020, which we understand to not be enforceable, was used as a basis from the RE to state the converters required some type of NERC CIP applicability. This is an extract from item 1. under Section V. Lessons Learned Discussion (page 6):

> *"While entities generally identified BES Cyber Assets effectively, in some cases entities did not identify BES Cyber Assets equipment performing supporting functions. For example, several entities misidentified Cyber Assets as communications equipment instead of BES Cyber Assets. Cybers Assets that seem to serve only a communication function such as switches and protocol converters may pose an impact to the BES within 15 minutes of their misuse. NERC, in a lessons learned document, recommends assessing whether all Cyber Assets can impact the BES within 15 minutes including communication Cyber Assets."*

The third publication is a set of proposed recommendations for clarity under a Standards Authorization Request titled CIP V5 TAG Modifications ERC and IRA under Project 2016-02 CIP Modifications from May 7, 2020. This document shows multiple diagrams with serial to IP converters being categorized as EACMS with system-to-system communications. As stated earlier, this is an improper categorization as no "*electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems*" is performed by the converters.

Inherently, communication networks and data communication links pose some level of risk to the BES. The client assessed devices on communications networks and links, such as a converters and transport routers/switches, and determined there is a limited possibility that compromise or misuse of could cause disruption to the BES within 15 minutes; but only in an event where a malicious actor altered telemetry data coming from the serially connected BCAs (such as an Remote Terminal) at the transmission stations to the Control Center, and the system operator then took manual action based on the data transmitted over the communication network and links. However, the probability of compromise or misuse was determined low and mitigated by the fact that such devices on communication networks and links are protected from unauthorized physical access as they are located within a secured PSP as the must connect to Electronic Access Points. Further, if communication networks and links

with the Transmission substations were to be lost, the client could manually control the assets at its substations.
However, based on the position indicated by the RE above in regard to converters in relation to BCAs, the RE agreed that regardless of whether the converters meets the definition of a BCA, they wanted them or their associated network switches to be placed within an ESP given that they are technically incapable of providing authentication/protocol break services to qualify as EACMS. As a result, they would need to be classified or protected as either BCAs and PCAs respectively or protected vice versa.

The Request

In light of the RE's communicated position per 'The Issue' section above, has NERC's formal position to the REs changed regarding the classification and protection of such devices used in communication networks and links?

- Specifically, if system-to-system serial communications between a TO's medium impact BCS connects to a TOP's BCS must any and all converters protect the connection by either enforcing an authentication break or by residing inside a defined ESP (thereby relying upon the ESP to provide the necessary protections)?
- In such cases, is it a pre-requisite that said converters must meet the definition of a BCA to justify such protections?

Unofficial Nomination Form

Project 2021-03 CIP-002 Transmission Owner Control Centers Standard Drafting Team

Do not use this form for submitting nominations. Use the electronic form to submit nominations for supplemental **Project 2021-03 CIP-002 Transmission Owner Control Centers (TOCC)** drafting team members by **8 p.m. Eastern, Wednesday, June 22, 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 Senior Standards Developer, Jordan Mallory (via email), or at 404-446-2589.

Background

There are currently four (4) Standards Authorization Requests (SARs) assigned to the project. The current standard drafting team (SDT) is working on a field test pursuant to one of the SARs regarding TOCC and is seeking supplemental members who will focus their attention on the other three (3) SARs:

- CIP-002 and CIP-014 - By modifying the standards to replace/update language with regards to "critical to the derivation of the Interconnection Reliability Operating Limits to appropriately identify Facilities, that if somehow compromised, could significantly impact the reliability of the Bulk Electric System (BES).
- Request for Interpretation CIP-002-5.1a - By providing clarification with regards to Requirement R1.
- Modifications to CIP-002 - To ensure all BES Cyber Systems' associated Cyber Assets (CA) are identified for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those CA could have on the reliable operations of the BES.

The current SDT members will be referred to Group A, and the supplemental team will be Group B. The two groups will work simultaneously on their assigned SARs and coordinate accordingly.

Standard(s) affected: CIP-002 and CIP-014

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

The time commitment for this project is expected to consist of a majority of conference calls, with occasional face-to-face meetings (an average of two full working days each meeting). The conference calls and face-to-face meetings will be scheduled as necessary to meet the agreed-upon timeline the drafting team sets forth. Team members may also have side projects, either individually or by sub-group, to present to the full drafting team for discussion and review. Lastly, an important component of the team effort is outreach. Drafting team members will be expected to conduct industry outreach during the development process to support a successful project outcome.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

Please briefly describe your experience and qualifications to serve on the requested Standard Drafting Team (Bio):
If you are currently a member of any NERC drafting team, please list each team here: ☐ Not currently on any active SAR or standard drafting team. ☐ Currently a member of the following SAR or standard drafting team(s):
If you previously worked on any NERC drafting team please identify the team(s): ☐ No prior NERC SAR or standard drafting team. ☐ Prior experience on the following team(s):
Acknowledgement that the nominee has read and understands both the *NERC Participant Conduct Policy* and the *Standard Drafting Team Scope* documents, available on NERC Standards Resources. ☐ Yes, the nominee has read and understands these documents.

Select each NERC Region in which you have experience relevant to the Project for which you are volunteering:		
☐ MRO ☐ NPCC ☐ RF	☐ SERC ☐ Texas RE ☐ WECC	☐ NA – Not Applicable

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

Select each Function[1] 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	

[1] 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:		E-mail:	
Name:		Telephone:	
Organization:		E-mail:	
Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

Standards Announcement

Project 2021-03 CIP-002 Transmission Owner Control Centers

Supplemental Drafting Team Nomination Period Open through June 22, 2022

Now Available

Nominations are being sought for supplemental drafting team members through **8 p.m. Eastern, Wednesday, June 22, 2022**. The current drafting team ("Group A") is working on a field test pursuant to the Standard Authorization Request (SAR) regarding Transmission Owner Control Centers. The supplemental drafting team members will be considered "Group B" and are expected to address three other SARs and will not focus on the CIP-002 field test.

Use the electronic form to submit a nomination. Contact Wendy Muller 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.

The time commitment for this project is expected to consist of a majority of conference calls, with occasional face-to-face meetings (an average of two full working days each meeting). The conference calls and face-to-face meetings will be scheduled as necessary to meet the agreed-upon timeline the drafting team sets forth. Team members may also have side projects, either individually or by sub-group, to present to the full drafting team for discussion and review. Lastly, an important component of the team effort is outreach. Drafting team members will be expected to conduct industry outreach during the development process to support a successful project outcome.

By submitting a nomination form, you are indicating your willingness and agreement to actively participate in conference calls and face-to-face meetings. Previous drafting team experience is beneficial but not required. See the project page and nomination form for additional information.

Next Steps

The Standards Committee is expected to appoint members to the drafting team in July 2022. Nominees will be notified shortly after they have been appointed.

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

For more information or assistance, contact Senior Standards Developer, Jordan Mallory (via email) or at (404) 446-2589. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify "Project 2021-03 Observer List" in the Description Box.

NERC

NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

CIP-002 Transmission Owner Control Centers (TOCCs) Field Test Questionnaire 3

Project 2021-03

Please complete the following questions to help us better understand your system.

As a NERC Control Center is applicable to specific configurations, an entity may have no CC, may have one, or could possibly have multiple CC locations. To the extent that an entity has multiple CC locations that control different BES Transmission Elements, the entity should complete a separate questionnaire for each CC location or clearly delineate between each CC location on the questionnaire as the individual outcomes of the application of Criterion 2.12 could be different.

1. Do the BES Cyber Systems associated with your Control Center meet any of the following CIP-002-5.1a criteria for High Impact? Please provide any clarifying comments below.

☐ Criteria 2.2 ☐ Criteria 2.4 ☐ Criteria 2.5 ☐ Criteria 2.7
☐ Criteria 2.8 ☐ Criteria 2.9 ☐ Criteria 2.10 ☐ None

____

____

____

2. Please populate the table below and provide an "aggregate weighted value" by summing the "weighted value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center.

Please submit a revised one-line that identifies each line that was included in your analysis.

Voltage Value of a Line	Weight Value per Line	Number of Lines	Aggregate Value
Less than 100kV	0		0
100 kV to 199 kV	250		
200 kV to 299 kV	700		
300 kV to 499 kV	1300		
500 kV and above	0		

Total Aggregate Weighted Value: ____
(Enter "Medium Risk" if number of 500 kV lines is greater than zero)

3. Are any of your BES Transmission Elements included as a part of an interface that has been defined as a permanent Flowgates in the Eastern Interconnection, a major transfer path within the Western Interconnection, or comparable interface in the ERCOT Interconnection (e.g., Generic Transmission Constraint) or the Quebec Interconnection? Please explain in the comment box below should you check unknown, or if you have any further clarifying comments.

☐ Yes ☐ No ☐ Unknown

____

____

____

4. Are any of your BES Transmission Elements included as part of a contingency for any permanent Flowgates in the Eastern Interconnection, major transfer paths within the Western Interconnection, or comparable monitored facility in the ERCOT Interconnection (e.g., Generic Transmission Constratin) or the Quebec Interconnection? Please explain in the comment box below should you check unknown, or if you have any further clarifying comments.

☐ Yes ☐ No ☐ Unknown

____

____

____

5. Were any of your BES Transmission Elements included as part of a prior outage for any permanent Flowgates in the Eastern Interconnection, major transfer paths within the Western Interconnection, or comparable monitored facility in the ERCOT Interconnection (e.g., Generic Transmission Constratin) or the Quebec Interconnection? Please explain in the comment box below should you check unknown, or if you have any further clarifying comments.

☐ Yes ☐ No ☐ Unknown

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____

____

6. Have any of your BES Transmission Elements been identified by your Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies? Please explain in the comment box below should you check unknown, or if you have any further clarifying comments.

   ☐ Yes ☐ No ☐ Unknown

   ____

   ____

   ____

7. Do you have any automatic Load shedding that is performed by a common control system that implements Load shed without human operator initiation? A common control system would exclude underfrequency load shedding (UFLS) and undervoltage load shedding (UVLS) that is implemented by individual relays located at discrete stations or substations. If you answer yes, please describe the purpose of the scheme and total peak load impacted.

   ☐ Yes ☐ No ☐ Unknown

   ____

   ____

   ____

8. Are any of your BES Transmission Elements included as a monitored element for any Remedial Action Schemes (RAS)? If you answer yes, please describe the purpose of the RAS and the impact to the BES if the RAS fails to operate as designed.

   ☐ Yes ☐ No ☐ Unknown

   ____

   ____

   ____

9. Are any of your BES Transmission Elements operated (i.e., opened or closed) via any Remedial Action Schemes (RAS) or Special Protection Systems (SPS)? If you answer yes, please describe the purpose of the RAS and the impact to the BES if the RAS fails to operate as designed.

   ☐ Yes ☐ No ☐ Unknown

   ____

   ____

10. Do you have any BES Transmission Elements providing the generation interconnection required to connect BES generator resource output equal to or greater than an aggregate of 1500 MW that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation resource to your interconnected neighbors (TOP/TSP/BA)?

☐ Yes ☐ No ☐ Unknown

11. Do you have any BES Transmission Elements that are critical to system restoration associated with Blackstart Resources?

☐ Yes ☐ No ☐ Unknown

12. Do you have any BES Transmission Elements that are included in the Cranking Paths and initial switching requirements of any Transmission Operator's restoration plan?

☐ Yes ☐ No ☐ Unknown

13. Can another entity de-energize your system from the BES via operation of their devices or remote control of your devices? What is the minimum number of breakers/switches that another single entity can remotely control in order to de-energize your system. If two or more entities must work cooperatively to de-energize your system while keeping other systems whole, then provide the minimum number of entities and breakers/switches needed to isolate your system. Please identify these breakers/switches on a revised one-line submittal.

____

____

____

____

____

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:	Modifications to CIP-002		
Date Submitted:	10/4/2021		
SAR Requester			
Name:	Latrice Harkness		
Organization:	NERC		
Telephone:	404-446-9728	Email:	latrice.harkness@nerc.net
SAR Type (Check as many as apply)			
☐ New Standard ☒ Revision to Existing Standard ☐ Add, Modify or Retire a Glossary Term ☐ Withdraw/retire an Existing Standard		☐ Imminent Action/ Confidential Issue (SPM Section 10) ☐ Variance development or revision ☐ Other (Please specify)	
Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)			
☐ Regulatory Initiation ☐ Emerging Risk (Reliability Issues Steering Committee) Identified ☐ Reliability Standard Development Plan		☐ NERC Standing Committee Identified ☐ Enhanced Periodic Review Initiated ☒ Industry Stakeholder Identified	
Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):			
The purpose of this project is to ensure that all BES Cyber Systems' associated Cyber Assets are identified for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those Cyber Assets could have on the reliable operation of the BES. Identification and categorization of these Cyber Assets supports appropriate protection against compromises. Without an accurate inventory of associated Cyber Assets, registered entities may fail to deploy appropriate controls to these Cyber Assets, which may lead to misoperation or instability in the BES.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
Electronic Access Control or Monitoring Systems (EACMS), Physical Access Control Systems (PACS), and Protected Cyber Assets (PCAs), if compromised, pose a threat to their associated BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (PCA), or (b) the security control function they perform (EACMS and PACS). This project will ensure the reliable operation of the BES by requiring the identification of these Cyber Assets so that the appropriate controls can be implemented.			

Requested information
Project Scope (Define the parameters of the proposed project):
This project will make revisions to CIP-002 to include the identification and categorization of certain Cyber Assets (EACMS, PACS, and PCAs) associated with high and medium impact BES Cyber Systems.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Revise CIP-002 to include the identification of EACMS, PACS, and PCA.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact is unknown at this time. However, a question will be asked during the comment period to ensure cost aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g*., Dispersed Generation Resources):
None.
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):
Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Interchange Coordinator or Interchange Authority, Reliability Coordinator, Transmission Operator, Transmission Owner
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
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 2016-02, Project 2021-03
Are there alternatives (e.g., guidelines, white paper, alerts, etc.) that have been considered or could meet the objectives? If so, please list the alternatives.
None.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.
[2] Consensus building activities are occasionally conducted by NERC and/or project review teams. They typically are conducted to obtain industry inputs prior to proposing any standard development project to revise, or develop a standard or definition.

Reliability Principles	
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	None.

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:	Modifications to CIP-002 and CIP-014		
Date Submitted:	May 26, 2021		
SAR Requester			
Name:	Dean LaForest		
Organization:	ISO New England		
Telephone:	413-387-8132	Email:	dlaforest@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?):			
This project provides revisions to CIP-002 and CIP-014 to clarify the responsibility of Reliability Coordinators, Planning Coordinators and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards. As it relates to the Transmission Planner and Planning Coordinator functions, the language “critical to the derivation of Interconnection Reliability Operating Limits (IROLs)” should be replaced/updated to appropriately identify Facilities that, if somehow compromised, could significantly impact the reliability of the Bulk Electric System (BES). Additionally this project will review the applicability of Facilities identified by the Reliability Coordinator as critical to the derivation of IROLs to CIP-002 and CIP-014.			
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):			
This project provides necessary clarification to identify Facilities identified by Reliability Coordinators, Planning Coordinators and Transmission Planners that warrant consideration under the CIP-002 and CIP-014 Reliability Standards. These clarifications will ensure that responsible entities are provided with the			

Requested information
necessary information to appropriately protect these Facilities, and correctly identify the responsible parties that provide the information applicable to the standards.
Project Scope (Define the parameters of the proposed project):
This project will make conforming changes to CIP-002 and CIP-014 as a result of Standard revisions from Project 2015-09. Project 2015-09 revised the requirements for determining and communicating System Operating Limits (SOLs) and IROLs used in the reliable planning and operation of the BES. These revisions necessitate that CIP-002 and CIP-014 be revised to clarify the Functional Entities responsible for communication of Facilities that warrant consideration under the CIP-002 and CIP-014 Reliability Standards. This will include review of criteria/applicability to determine Facilities identified per Attachment 1 of CIP-002 and the Applicability section of CIP-014 for potential revision for responsible entities. This team will work to coordinate with other ongoing CIP development projects to ensure alignment with any changes to definition or standards and requirements.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Revisions to CIP-002 and CIP-014 to include: (1) Identifying Functional Entities that identify Facilities applicable to CIP-002 and CIP-014. (2) Identifying Functional Entities responsible for the communication of the identified Facilities. (3) Applicability sections to be reviewed and revised accordingly. (4) Determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP’s Planning Assessment for the Near-Term Transmission Planning Horizon. (5) Determine the appropriateness of the identification of Facilities critical to the derivation of IROLs by the RC.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact of implementation of the proposed Standard is dependent upon the method(s) by which a Responsible Entity chooses to meet any additional Requirements. However, a question will be asked during the SAR comment period to ensure cost aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
Submitter asserts there are no unique characteristics associated with BES facilities that will be impacted by this proposed standard development project.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
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 2016-02 Modifications to CIP 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.
None at this time.

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.

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

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
	None identified

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 2021-03 CIP-002 Transmission Owner Control Centers

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on the **two posted standard authorization requests (SARs) for Project 2021-03 CIP-002** by **8 p.m. Eastern, Wednesday, December 21, 2022.**

Additional information is available on the project page. If you have questions, contact Senior Standards Developer, Jordan Mallory (via email), or at 470-373-3381.

Background Information

NERC Project 2021-03 CIP-002 Transmission Owner Control Centers received two additional SARs. They are outlined below.

CIP-002 and CIP-014 SAR – Accepted by the Standards Committee on July 21, 2021

The purpose of the CIP-002 and CIP-014 SAR is to clarify the responsibility of Reliability Coordinators, Planning Coordinators and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards. As it relates to the Transmission Planner and Planning Coordinator functions, the language “critical to the derivation of Interconnection Reliability Operating Limits (IROLs)” should be replaced/updated to appropriately identify Facilities that, if somehow compromised, could significantly impact the reliability of the Bulk Electric System (BES). Additionally this project will review the applicability of Facilities identified by the Reliability Coordinator as critical to the derivation of IROLs to CIP-002 and CIP-014.

Modifications to CIP-002 SAR – Accepted by the Standards Committee on February 16, 2022

The purpose of the Modifications to CIP-002 SAR is to ensure that all BES Cyber Systems’ associated Cyber Assets are identified for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those Cyber Assets could have on the reliable operation of the BES. Identification and categorization of these Cyber Assets supports appropriate protection against compromises. Without an accurate inventory of associated Cyber Assets, registered entities may fail to deploy appropriate controls to these Cyber Assets, which may lead to misoperation or instability in the BES.

Questions

1. Do you agree with the proposed scope as described in the CIP-002 and CIP-014 SAR? 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. Do you agree with the proposed scope as described in the modifications to CIP-002 SAR? 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:

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

   Comments:

Standards Announcement

Project 2021-03 CIP-002 Transmission Owner Control Centers Standard Authorization Requests

Formal Comment Period Open through December 21, 2022

Now Available

A 30-day formal comment period for the **Project 2021-03 CIP-002 Transmission Owner Control Centers Standard Authorization Requests**, is open through **8 p.m. Eastern, Wednesday, December 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 Senior Standards Developer, Jordan Mallory (via email) or at (404) 446-2589. Subscribe to this project's observer mailing list by selecting "NERC Email Distribution Lists" from the "Service" drop-down menu and specify “Project 2021-03 CIP-002 Transmission Owner Control Centers Observer List” in the Description Box.

RELIABILITY CORPORATION

Atlanta, GA 30326
404-446-2560 | www.nerc.com

Comment Report

Project Name:	2021-03 CIP-002 Transmission Owner Control Centers | Standard Authorization Requests
Comment Period Start Date:	11/22/2022
Comment Period End Date:	12/21/2022
Associated Ballots:	

There were 30 sets of responses, including comments from approximately 105 different people from approximately 89 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 CIP-002 and CIP-014 SAR? 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. Do you agree with the proposed scope as described in the modifications to CIP-002 SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

3. Provide any additional comments for the 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
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Amber Skillern	East Kentucky Power Cooperative	1	SERC
					Ryan Strom	Buckeye Power, Inc.	5	RF
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Scott Brame	NC Electric Membership Corporation	3,4,5	SERC
					Nick Fogleman	Prairie Power, Inc.	1	SERC
					Scott Berry	Wabash Valley Power Association	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
					LaTroy Brumfield	American Transmission Company, LLC	1	MRO
					Bryan Sherrow	Kansas City Board Of Public Utilities	1	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					George Brown	Acciona Energy North America	5	MRO
					Jaimin Patel	Saskatchewan Power Corporation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF

Pacific Gas and Electric Company	Michael Johnson	1,3,5	WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					Frank Lee	Pacific Gas and Electric Company	5	WECC
California ISO	Monika Montez	2	WECC	ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002	Monika Montez	CAISO	2	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kathleen Goodman	ISO-NE	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Elizabeth Davis	PJM	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Andrew Gallo	Electric Reliability Council of Texas, Inc.	2	Texas RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern	6	SERC

						Company Generation		
NPCC	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Sheraz Majid	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					John Hastings	National Grid	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Dan Kopin	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
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	NPCC
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Michael Jones	National Grid	3	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

1. Do you agree with the proposed scope as described in the CIP-002 and CIP-014 SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support the proposed scope for this SAR because it is unclear the reliability gap associated with RC, PC and TP responsibilities in the identification of critical facilities associated with IROLs. While these registered entities are not identified in CIP-002 or CIP-014 directly, the establishment, identification and communication of IROLs is already contained in other NERC O&P Reliability Standards. Specifically, during Project 2015-09 (Establish and Communicate System Operating Limits) these obligations were addressed. Adding redundant requirements in CIP-002 and CIP-014 would only add unnecessary and duplicative obligations on registered entities. It is also important to note that the modifications made under Project 2015-09 to address these issues have not gone into effect, so at this time it is unknown whether the changes made are sufficient to fully address the concerns identified in this proposed SAR. FAC-014-3, Requirement R5 requires RCs to provide information to PCs, TPs, GOs and TOs (see subparts 5.2 & 5.6) and sub-part R5.6 requires RCs to provide “Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.” The concerns expressed in this SAR are unnecessary and would add language to CIP-002 and CIP-014 that would create duplicative Requirements in those Reliability Standards and necessitate adding FAC-014-3 to the project scope in order to make conforming changes to that Reliability Standard. For these reasons, we do not support the proposed SAR.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy supports the comments proposed by EEI, “EEI does not support the proposed scope for this SAR because it is unclear the reliability gap associated with RC, PC and TP responsibilities in the identification of critical facilities associated with IROLs. While these registered entities are not identified in CIP-002 or CIP-014 directly, the establishment, identification and communication of IROLs is already contained in other NERC O&P Reliability Standards. Specifically, during Project 2015-09 (Establish and Communicate System Operating Limits) these obligations were addressed. Adding redundant requirements in CIP-002 and CIP-014 would only add unnecessary and duplicative obligations on registered entities. It is also important to note that the modifications made under Project 2015-09 to address these issues have not gone into effect, so at this time it is unknown whether the changes made are sufficient to fully address the concerns identified in this proposed SAR. FAC-014-3, Requirement R5 requires RCs to provide information to PCs, TPs, GOs and TOs (see subparts 5.2 & 5.6) and sub-part R5.6 requires RCs to provide “Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.” The concerns expressed in this SAR are unnecessary and would add language to CIP-002 and CIP-014 that would create duplicative Requirements in those Reliability Standards and necessitate adding	

FAC-014-3 to the project scope in order to make conforming changes to that Reliability Standard. For these reasons, we do not support the proposed SAR.”	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
This proposed adjustment is out of the scope of responsibility for the PC,TP and RC. If Facilities are not being considered in the applicability section of the standard, than that should be addressed first. Interconnections which are the responsibility of the owners drives the inclusion in these standards, so the responsibility should be kept there. For the purpose of security owners to have the necessary information to assess the standards, the information necessary to assess does not sit with the PC,TP or RC, nor should they. If issues exist with a facility and the location, the it should be considered as a contingency and addressed in TPL-001.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	No
Document Name	
Comment	
Exelon is aligning with EEI in response to this question for both 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	No
Document Name	
Comment	

Southern Company is in full agreement with the following EEI Comments:

EEI does not support the proposed scope for this SAR because it is unclear the reliability gap associated with RC, PC and TP responsibilities in the identification of critical facilities associated with IROLs. While these registered entities are not identified in CIP-002 or CIP-014 directly, the establishment, identification and communication of IROLs is already contained in other NERC O&P Reliability Standards. Specifically, during Project 2015-09 (Establish and Communicate System Operating Limits) these obligations were addressed. Adding redundant requirements in CIP-002 and CIP-014 would only add unnecessary and duplicative obligations on registered entities. It is also important to note that the modifications made under Project 2015-09 to address these issues have not gone into effect, so at this time it is unknow whether the changes made are sufficient to fully address the concerns identified in the proposed SAR. While we are aware of cost recovery issues that remain unresolved with the identification of IROLs at entity facilities, a NERC Reliability Standard is not an appropriate venue to address such concerns. For these reasons, we do not support the proposed SAR.

Likes 0	
Dislikes 0	

Response

Justin Kuehne - AEP - 3,5,6

Answer	No
Document Name	

Comment

AEP is in agreement with the overall sentiment laid out in EEI's comments on this project. We feel that the proposed scope of this project will lead to duplicative requirements in these standards with little benefit to the safety and reiliability of the BES. Please see EEI's comment below:

EEI does not support the proposed scope for this SAR because it is unclear the reliability gap associated with RC, PC and TP responsibilities in the identification of critical facilities associated with IROLs. While these registered entities are not identified in CIP-002 or CIP-014 directly, the establishment, identification and communication of IROLs is already contained in other NERC O&P Reliability Standards. Specifically, during Project 2015-09 (Establish and Communicate System Operating Limits) these obligations were addressed. Adding redundant requirements in CIP-002 and CIP-014 would only add unnecessary and duplicative obligations on registered entities. It is also important to note that the modifications made under Project 2015-09 to address these issues have not gone into effect, so at this time it is unknown whether the changes made are sufficient to fully address the concerns identified in this proposed SAR. FAC-014-3, Requirement R5 requires RCs to provide information to PCs, TPs, GOs and TOs (see subparts 5.2 & 5.6) and sub-part R5.6 requires RCs to provide "Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months." The concerns expressed in this SAR are unnecessary and would add language to CIP-002 and CIP-014 that would create duplicative Requirements in those Reliability Standards and necessitate adding FAC-014-3 to the project scope in order to make conforming changes to that Reliability Standard. For these reasons, we do not support the proposed SAR.

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC agrees with ACES comments below: We do not feel the scope of this SAR is correct for Transmission Owner Control Centers (TOCC). The proposed SAR modifications dilute the project. If NERC or Industry feels like there needs to be identification of PACS, EACMS, and PCA under CIP-002, then there should be a separate specific project not scope creep on this project. This projects background and purpose have nothing to do with PACS, EACMS or PCAs. Adding this to the SAR will certainly extend this project beyond the timeline established for this project which is not acceptable.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren agrees with and supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FirstEnergy feels the description of this SAR is too vague and not clear on what risk is being addressed. We find no need or added value for the proposed SAR.	
Likes 0	

Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation agrees with Exelon and EEI comments. Kimberly Turco on behalf of Constellation Segements 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) supports the comments as submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
We do not feel the scope of this SAR is correct for Transmission Owner Control Centers (TOCC). The proposed SAR modifications dilute the project. If NERC or Industry feels like there needs to be identification of PACS, EACMS, and PCA under CIP-002, then there should be a separate specific project	

not scope creep on this project. This projects background and purpose have nothing to do with PACS, EACMS or PCAs. Adding this to the SAR will certainly extend this project beyond the timeline established for this project which is not acceptable.	
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 (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	
Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
Please see the MRO NSRF's comments in question three.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation agrees with Exelon and EEI comments.	

Alison Mackellar on behalf of Constellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments

Answer	No
Document Name	

Comment

PG&E does not agree with the proposed scope of the SAR and agrees with the input provided by EEI – the contents of the SAR for CIP-002 and CIP-014 were addressed in Project 2015-09 “Establish and Communicate System Operating Limits” and there is no reason to duplicate them in CIP-002 and CIP-014. While it is not a good practice to place references to other Standards within a Standard, a suitable alternative is to make references to the earlier Project 2015-09 work in Implementation Guidance or Technical Rationale documentation.

Likes 0	
Dislikes 0	

Response

Jennifer Buckman - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

SIGE (Southern Indiana Gas and Electric) supports the comments as submitted by the Edison Electric Institute. SIGE also recommends the SDT add clarification to the SAR regarding the determination of appropriateness of the identification of Facilities critical to the derivation of IROLs by the RC and how it may impact the categorization of the BES Assets.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6

Answer	No
Document Name	

Comment

AZPS does not support the proposed scope for this SAR and agrees with the following EEI comments regarding the CIP-002 and CIP-014 SAR “it is unclear of the reliability gap associated with RC, PC and TP responsibilities in the identification of critical facilities associated with IROLs. While these registered entities are not identified in CIP-002 or CIP-014 directly, the establishment, identification, and communication of IROLs is already contained in other NERC O&P Reliability Standards. Specifically, during Project 2015-09 (Establish and Communicate System Operating Limits) these obligations were addressed. Adding redundant requirements in CIP-002 and CIP-014 would only add unnecessary and duplicative obligations on registered entities. It is also important to note that the modifications made under Project 2015-09 to address these issues have not gone into effect, so at this time it is unknown whether the changes made are sufficient to fully address the concerns identified in this proposed SAR. FAC-014-3, Requirement R5 requires RCs to provide information to PCs, TPs, GOs and TOs (see subparts 5.2 & 5.6) and sub-part R5.6 requires RCs to provide “Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.” The concerns expressed in this SAR are unnecessary and would add language to CIP-002 and CIP-014 that would create duplicative Requirements in those Reliability Standards and necessitate adding FAC-014-3 to the project scope in order to make conforming changes to that Reliability Standard. For these reasons, we do not support the proposed SAR.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

MP is in support of EEI's comments related to CIP-002.

Likes 0	
Dislikes 0	

Response

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 1,3

Answer	No
Document Name	

Comment

PNM expresses support of EEI comments. "EEI does not support the proposed scope for this SAR because it is unclear the reliability gap associated with RC, PC and TP responsibilities in the identification of critical facilities associated with IROLs. While these registered entities are not identified in CIP-002 or CIP-014 directly, the establishment, identification and communication of IROLs is already contained in other NERC O&P Reliability Standards. Specifically, during Project 2015-09 (Establish and Communicate System Operating Limits) these obligations were addressed. Adding redundant requirements in CIP-002 and CIP-014 would only add unnecessary and duplicative obligations on registered entities. It is also important to note that the modifications made under Project 2015-09 to address these issues have not gone into effect, so at this time it is unknown whether the changes made are sufficient to fully address the concerns identified in this proposed SAR. FAC-014-3, Requirement R5 requires RCs to provide information to PCs, TPs, GOs and TOs (see subparts 5.2 & 5.6) and sub-part R5.6 requires RCs to provide “Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.” The concerns expressed in this SAR are unnecessary and would add language to CIP-002 and CIP-014 that would create duplicative Requirements in those Reliability Standards and necessitate adding FAC-014-3 to the project scope in order to make conforming changes to that Reliability Standard. For these reasons, we do not support the proposed SAR."

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	Yes
Document Name	

Comment

Request clarification of the proposed update. Is this IROL update identifying sites or systems?

Recommend this scope include IROLs that are shared among entities.

Likes 0	
Dislikes 0	

Response

Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC

Answer	Yes
Document Name	

Comment

Request clarification of the proposed update. Is this IROL update identifying sites or systems?

Recommend this scope include IROLs that are shared among entities.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002	
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	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	

Document Name	
Comment	
No response received from Standard Owner(s) or SMEs	
Likes 0	
Dislikes 0	
Response	

2. Do you agree with the proposed scope as described in the modifications to CIP-002 SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	No
Document Name	
Comment	

PNM does not agree wi the proposed scope for CIP-002 SAR. PNM supports EEI comments.

EEI does not support the proposed scope for this SAR because it is unclear the reliability gap that this SAR intends to close. While it is clear that responsible entities under CIP-002 must identify BES Cyber Systems and their associated BES Cyber assets, the current standard does not implicitly require the development of a list of those assets. This is because lists do not guarantee assets are protected. Moreover, administratively, mistakes in documentation can happen even when affected assets have been identified and properly protected. Additionally, this SAR proposes to move CIP-002 away from a Risk-Based standard to one that is a zero-defect standard which does little to improve BES Reliability, while creating significant compliance burden and risk for responsible entities.

It is also worth considering whether the formal development of discrete lists of Cyber Assets is a forward-looking approach that will last as technology evolves. While over the life of the CIP standards, electronic access control has and will continue to morph from dedicated Cyber Assets (i.e., a discrete HW firewall, a discrete HW domain controller server, etc.) to a function performed in ever more distributed ways. Zero Trust principles may affect access policies. Zero Trust could also result in thousands of logical ESPs around sessions, and thus thousands of EACMS. The concept of EACMS as a discrete 'Cyber Asset' that you can be put on a list will lose meaning over time, rendering a standard obsolete. The technology is headed to electronic access control being a highly distributed function enforced throughout the infrastructure, not a list of dedicated Cyber Assets.

It is also worth noting that virtualization is abstracting 'programmable electronic devices' into a generic hardware resource pool, on top of which many functions are implemented. It is our understanding that the Project 2016-02 SDT is working to incorporate into the PCA definition not only the sharing of a local network, but the sharing of a hypervisor's CPU and memory resources.   This type of change will result in dynamic system operation, with a virtual machine becoming a PCA based on where it is executing at the moment. Such a scenario will make the development of discrete lists of categorized BES Cyber Assets nearly impossible, possibly rendering the proposed changes obsolete before the Reliability Standard ever become enforceable.

Likes 0	
Dislikes 0	
Response	

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

MP supports EEI's comments.

Likes 0	

Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	No
Document Name	
Comment	

AZPS does not support the proposed scope for this SAR because we believe that the current CIP-002 standard clearly requires the identification of high and medium impact BES Cyber Systems while also defining associated EACMS, PACS, and PCAs. Applicability is then used throughout the CIP standards to apply enforceable requirements to these devices. AZPS also supports the following EEI comments related to the CIP-002 SAR “The current standard does not implicitly require the development of a list of those assets. This is because lists do not guarantee assets are protected. Moreover, administratively, mistakes in documentation can happen even when affected assets have been identified and properly protected. Additionally, this SAR proposes to move CIP-002 away from a Risk-Based standard to one that is a zero-defect standard which does little to improve BES Reliability, while creating significant compliance burden and risk for responsible entities.

It is also worth considering whether the formal development of discrete lists of Cyber Assets is a forward-looking approach that will last as technology evolves. While over the life of the CIP standards, electronic access control has and will continue to morph from dedicated Cyber Assets (i.e., a discrete HW firewall, a discrete HW domain controller server, etc.) to a function performed in ever more distributed ways. Zero Trust principles may affect access policies. Zero Trust could also result in thousands of logical ESPs around sessions, and thus thousands of EACMS. The concept of EACMS as a discrete ‘Cyber Asset’ that you can be put on a list will lose meaning over time, rendering a standard obsolete. The technology is headed to electronic access control being a highly distributed function enforced throughout the infrastructure, not a list of dedicated Cyber Assets.

It is also worth noting that virtualization is abstracting ‘programmable electronic devices’ into a generic hardware resource pool, on top of which many functions are implemented. It is our understanding that the Project 2016-02 SDT is working to incorporate into the PCA definition not only the sharing of a local network, but the sharing of a hypervisor’s CPU and memory resources. This type of change will result in dynamic system operation, with a virtual machine becoming a PCA based on where it is executing at the moment. Such a scenario will make the development of discrete lists of categorized BES Cyber Assets nearly impossible, possibly rendering the proposed changes obsolete before the Reliability Standard ever become enforceable.”

Likes 0	
Dislikes 0	
Response	
Jennifer Buckman - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	

SIGE does not support the proposed scope for this SAR because the existing CIP standards address the identification of EACMS, PACS, and PCAs. The language referring to BES Cyber Systems and their associated EACMS, PACS, and PCA appears in the CIP Requirements 80 times. An additional regulatory requirement to add them to an identified list is redundant and administratively burdensome with no clearly identified reliability benefit.

Likes 0	
Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	No
Document Name	
Comment	

PG&E understands the intent of the SAR to explicitly identify EACMS, PACS, and PCA which many Entities have been doing since the early days of CIP-002-5.1a, but we agree with the input by EEI that the creation of a discrete list of Cyber Asset for those devices is going to be more difficult as virtualization expands within the industry. This will be especially true for EACMS as the firewall and access point move from specific devices to potentially every Cyber Asset. The SAR should be modified to address these trends so it does not restrict what a drafting team can do to satisfy NERC's desire to make sure all BCS associated Cyber Assets are identified and appropriately protected.

Likes 0	
Dislikes 0	
Response	
Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	

We acknowledge that there is a gap in CIP standards on the identification and categorization of cyber assets, but we believe that this gap should not be addressed in CIP-002. The ESP and PSP concepts are not relevant for the assessment performed in regard to the CIP-002 standard, nor EACMS, PCA, and PACS. Bringing these types of cyber assets and concepts into the scope of CIP-002 brings an undesirable burden on demonstrating compliance with the CIP-002 standard, and would require even more multidisciplinary expertise to perform the assessment.

This gap should be filled in CIP standards that already address these concepts and types of cyber assets.

Recommend including Glossary changes to support this SAR.

Please consider the identification of 1) assets in the cloud, and 2) third-party cyber assets.

Request use cases for cyber assets a) on-site entity owned, b) on-site third party owned, c) off-site entity owned and d) off-site third-party owned. And conforming changes in the rest of the CIP Standards.

Request addressing other CIP-002 gaps like the threshold for new assets which have no prior history. Some existing thresholds depend on the prior year’s information.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5,6

Answer	No
Document Name	

Comment

Constellation agrees with Exelon and EEI comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Please see the MRO NSRF's comments in question three.

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 (EEI) for question #2.

Likes 0	

Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
If adding PACS, PCA, and EACMS to the scope of CIP-002 then those should be updated as a part of Project 2016-02 as there are new Cyber Assets coming into scope under that project or make this a project post Project 2016-02 approval. Further if as an industry we add to CIP-002's scope, not making this change as a part of 2016-02 will require programmatic changes again in the near future for the new asset and sub asset types creating increased and unnecessary compliance burden.	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE does not support the proposed scope for this SAR because the existing CIP standards address the identification of EACMS, PACS, and PCAs. The language referring to BES Cyber Systems and their associated EACMS, PACS, and PCA appears in the CIP Requirements 80 times. An additional regulatory requirement to add them to an identified list is redundant and administratively burdensome with no clearly identified reliability benefit.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation agrees with Exelon and EEI comments.	

Kimberly Turco on behalf of Constellation Segements 5 and 6.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC

Answer	No
Document Name	

Comment

We acknowledge that there is a gap in CIP standards on the identification and categorization of cyber assets, but we believe that this gap should not be addressed in CIP-002. The ESP and PSP concepts are not relevant for the assessment performed in regard of CIP-002 standard, nor EACMS, PCA and PACS. Bringing these types of cyber assets and concepts into the scope of CIP-002 brings an undesirable burden on demonstrating compliance to CIP-002 standard, and would require even more multidisciplinary expertise to perform the assessment.

This gap should be filled in CIP standards that already address these concepts and types of cyber assets.

Recommend including Glossary changes to support this SAR.

Please consider identification of 1) assets in the cloud, 2) third-party cyber assets.

Request use cases for cyber assets a) on-site entity owned, b) on-site third party owned, c) off-site entity owned and d) off-site third-party owned. And conforming changes in the rest of the CIP Standards.

Request addressing other CIP-002 gaps like threshold for new assets which have no prior history. Some existing thresholds depend on the prior year's information.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FirstEnergy is supportive of EEI comments which state:

EEI does not support the proposed scope for this SAR because it is unclear the reliability gap that this SAR intends to close. While it is clear that responsible entities under CIP-002 must identify BES Cyber Systems and their associated BES Cyber assets, the current standard does not implicitly require the development of a list of those assets. This is because lists do not guarantee assets are protected. Moreover, administratively, mistakes in documentation can happen even when affected assets have been identified and properly protected. Additionally, this SAR proposes to move CIP-002 away from a Risk-Based standard to one that is a zero-defect standard which does little to improve BES Reliability, while creating significant compliance burden and risk for responsible entities.

It is also worth considering whether the formal development of discrete lists of Cyber Assets is a forward-looking approach that will last as technology evolves. While over the life of the CIP standards, electronic access control has and will continue to morph from dedicated Cyber Assets (i.e., a discrete HW firewall, a discrete HW domain controller server, etc.) to a function performed in ever more distributed ways. Zero Trust principles may affect access policies. Zero Trust could also result in thousands of logical ESPs around sessions, and thus thousands of EACMS. The concept of EACMS as a discrete 'Cyber Asset' that you can be put on a list will lose meaning over time, rendering a standard obsolete. The technology is headed to electronic access control being a highly distributed function enforced throughout the infrastructure, not a list of dedicated Cyber Assets.

It is also worth noting that virtualization is abstracting 'programmable electronic devices' into a generic hardware resource pool, on top of which many functions are implemented. It is our understanding that the Project 2016-02 SDT is working to incorporate into the PCA definition not only the sharing of a local network, but the sharing of a hypervisor's CPU and memory resources.   This type of change will result in dynamic system operation, with a virtual machine becoming a PCA based on where it is executing at the moment. Such a scenario will make the development of discrete lists of categorized BES Cyber Assets nearly impossible, possibly rendering the proposed changes obsolete before the Reliability Standard ever become enforceable.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Ameren agrees with and supports EEI comments.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AEPC agrees with ACES comments below: If adding PACS, PCA, and EACMS to the scope of CIP-002 then those should be updated as a part of Project 2016-02 as there are new Cyber Assets coming into scope under that project or make this a project post Project 2016-02 approval. Further if as an industry we add to CIP-002's scope, not making this change as a part of 2016-02 will require programmatic changes again in the near future for the new asset and sub asset types creating increased and unnecessary compliance burden. If adding PACS, PCA, and EACMS to the scope of CIP-002 then those should be updated as a part of Project 2016-02 as there are new Cyber Assets coming into scope under that project or make this a project post Project 2016-02 approval. Further if as an industry we add to CIP-002's scope, not making this change as a part of 2016-02 will require programmatic changes again in the near future for the new asset and sub asset types creating increased and unnecessary compliance burden.

Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	No
Document Name	
Comment	

The SAR specifies "Revise CIP-002 to include the identification of EACMS, PACS, and PCA." While it is important that these Cyber Assets be properly identified and categorized, this is beyond the scope of CIP-002. EACMS and PCA don't exist without an ESP which is drawn in CIP-005 in order to protect BES Cyber Assets identified in CIP-002. Similar for PACS and PSPs in CIP-006. The SDT must have the flexibility to address these gaps in the standards without being limited to looking only at CIP-002.

Likes 0	
Dislikes 0	
Response	
Justin Kuehne - AEP - 3,5,6	
Answer	No
Document Name	
Comment	

AEP is in agreement with the overall sentiment laid out in EEI's comments on this SAR. Please see EEI's comment below:

EEI does not support the proposed scope for this SAR because it is unclear the reliability gap that this SAR intends to close. While it is clear that responsible entities under CIP-002 must identify BES Cyber Systems and their associated BES Cyber assets, the current standard does not implicitly require the development of a list of those assets. This is because lists do not guarantee assets are protected. Moreover, administratively, mistakes in documentation can happen even when affected assets have been identified and properly protected. Additionally, this SAR proposes to move CIP-002 *away from a Risk-Based standard to one that is a zero-defect standard which does little to improve BES Reliability, while creating significant compliance burden and risk for responsible entities.*

It is also worth considering whether the formal development of discrete lists of Cyber Assets is a forward-looking approach that will last as technology evolves. While over the life of the CIP standards, electronic access control has and will continue to morph from dedicated Cyber Assets (i.e., a discrete HW firewall, a discrete HW domain controller server, etc.) to a function performed in ever more distributed ways. Zero Trust principles will drive this function even further over time as access policies are enforced throughout infrastructures. Zero Trust will drive the industry from network edge perimeters to protection of each system access. In other words, thousands of logical ESPs around sessions, and thus thousands of EACMS. The concept of EACMS as a discrete 'Cyber Asset' that you can be put on a list will lose meaning over time, rendering a standard obsolete. The technology is headed to electronic access control being a highly distributed function enforced throughout the infrastructure, not a list of dedicated Cyber Assets.

It is also worth noting that virtualization is abstracting 'programmable electronic devices' into a generic hardware resource pool, on top of which many functions are implemented. It is our understanding that the Project 2016-02 SDT is working to incorporate into the PCA definition not only the sharing of a local network, but the sharing of a hypervisor's CPU and memory resources. This type of change will result in dynamic system operation, with a virtual machine becoming a PCA based on where it is executing at the moment. Such a scenario will make the development of discrete lists of categorized BES Cyber Assets nearly impossible, possibly rendering the proposed changes obsolete before the Reliability Standard ever become enforceable.

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 is in full agreement with the following EEI Comments:

EEI does not support the proposed scope for this SAR because it is unclear the reliability gap that this SAR intends to close. While it is clear that responsible entities under CIP-002 must identify BES Cyber Systems and their associated BES Cyber assets, the current standard does not implicitly require the development of a list of those assets. This is because lists do not in of themselves guarantee assets are protected. Moreover, administratively, mistakes in documentation can happen even when affected assets have been identified and properly protected. Additionally, this SAR proposes to move CIP-002 away from a Risk-Based standard to one that is a zero-defect standard which does little to improve BES Reliability, while creating significant compliance burden and risk for responsible entities.

It is also worth considering whether the formal development of discrete lists of Cyber Asset is a forward-looking approach that will last as technology evolves. While over the two-decade life of the CIP standards, electronic access control has and will continue to morph from dedicated Cyber Assets (i.e., a discrete HW firewall, a discrete HW domain controller server, etc.) to a function performed in ever more distributed ways. Zero Trust principles will drive this function into literally everything over time as access policies are enforced throughout infrastructures. Zero Trust will drive us from network edge perimeters to protection of each system access; in other words, thousands of logical ESPs around sessions, and thus thousands of EACMS. The concept of EACMS as a discrete 'Cyber Asset' that you can be put on a list will lose meaning over time. The technology is headed to electronic access control being a highly distributed function enforced throughout the infrastructure, not a list of dedicated Cyber Assets (although some will be dedicated).

It is also worth considering that virtualization is abstracting 'programmable electronic devices' into a generic hardware resource pool, on top of which many functions are implemented. It is our understanding that the Project 2016-02 SDT is working to incorporate into the PCA definition not only the sharing of a local network, but the sharing of a hypervisor's CPU and memory resources. This type of change will result in very dynamic system operation, with a virtual machine becoming a PCA based on where it is executing at the moment. Such a scenario will make the development of

discrete lists of categorized BES Cyber Assets nearly impossible, possibly rendering the proposed changes obsolete before the Reliability Standard ever become enforceable.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	No
Document Name	
Comment	
Exelon is aligning with EEI in response to this question for both Segments 1 and 3.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP supports the comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

NV Energy supports the comments proposed by EEI, “EEI does not support the proposed scope for this SAR because it is unclear the reliability gap that this SAR intends to close. While it is clear that responsible entities under CIP-002 must identify BES Cyber Systems and their associated BES Cyber assets, the current standard does not implicitly require the development of a list of those assets. This is because lists do not guarantee assets are protected. Moreover, administratively, mistakes in documentation can happen even when affected assets have been identified and properly protected. Additionally, this SAR proposes to move CIP-002 away from a Risk-Based standard to one that is a zero-defect standard which does little to improve BES Reliability, while creating significant compliance burden and risk for responsible entities.

It is also worth considering whether the formal development of discrete lists of Cyber Assets is a forward-looking approach that will last as technology evolves. While over the life of the CIP standards, electronic access control has and will continue to morph from dedicated Cyber Assets (i.e., a discrete HW firewall, a discrete HW domain controller server, etc.) to a function performed in ever more distributed ways. Zero Trust principles may affect access policies. Zero Trust could also result in thousands of logical ESPs around sessions, and thus thousands of EACMS. The concept of EACMS as a discrete ‘Cyber Asset’ that you can be put on a list will lose meaning over time, rendering a standard obsolete. The technology is headed to electronic access control being a highly distributed function enforced throughout the infrastructure, not a list of dedicated Cyber Assets.

It is also worth noting that virtualization is abstracting ‘programmable electronic devices’ into a generic hardware resource pool, on top of which many functions are implemented. It is our understanding that the Project 2016-02 SDT is working to incorporate into the PCA definition not only the sharing of a local network, but the sharing of a hypervisor’s CPU and memory resources. This type of change will result in dynamic system operation, with a virtual machine becoming a PCA based on where it is executing at the moment. Such a scenario will make the development of discrete lists of categorized BES Cyber Assets nearly impossible, possibly rendering the proposed changes obsolete before the Reliability Standard ever become enforceable.”

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 scope for this SAR because it is unclear the reliability gap that this SAR intends to close. While it is clear that responsible entities under CIP-002 must identify BES Cyber Systems and their associated BES Cyber assets, the current standard does not implicitly require the development of a list of those assets. This is because lists do not guarantee assets are protected. Moreover, administratively, mistakes in documentation can happen even when affected assets have been identified and properly protected. Additionally, this SAR proposes to move CIP-002 away from a Risk-Based standard to one that is a zero-defect standard which does little to improve BES Reliability, while creating significant compliance burden and risk for responsible entities.

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It is also worth noting that virtualization is abstracting ‘programmable electronic devices’ into a generic hardware resource pool, on top of which many functions are implemented. It is our understanding that the Project 2016-02 SDT is working to incorporate into the PCA definition not only the sharing of a local network, but the sharing of a hypervisor’s CPU and memory resources. This type of change will result in dynamic system operation, with a

virtual machine becoming a PCA based on where it is executing at the moment. Such a scenario will make the development of discrete lists of categorized BES Cyber Assets nearly impossible, possibly rendering the proposed changes obsolete before the Reliability Standard ever become enforceable.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	Yes
Document Name	
Comment	
We acknowledge that there is a gap in CIP standards on the identification and categorization of cyber assets, but we believe that this gap should not be addressed in CIP-002. The ESP and PSP concepts are not relevant for the assessment performed in regard of CIP-002 standard, nor EACMS, PCA and PACS. Bringing these types of cyber assets and concepts into the scope of CIP-002 brings an undesirable burden on demonstrating compliance to CIP-002 standard, and would require even more multidisciplinary expertise to perform the assessment. This gap should be filled in CIP standards that already address these concepts and types of cyber assets. Recommend including Glossary changes to support this SAR. Please consider identification of 1) assets in the cloud, 2) third-party cyber assets. Request use cases for cyber assets a) on-site entity owned, b) on-site third party owned, c) off-site entity owned and d) off-site third-party owned. And conforming changes in the rest of the CIP Standards. Request addressing other CIP-002 gaps like threshold for new assets which have no prior history. Some existing thresholds depend on the prior year's information.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
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	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	
Document Name	
Comment	
No response received from Standard Owner(s) or SMEs	
Likes 0	
Dislikes 0	
Response	

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

Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	
Document Name	
Comment	

If there is a Standard Drafting Team that addresses the IROL question, recommend that SDT include expertise in 1) IROLs and 2) CIP.

This posting is confusing. These two SARs are project 2021-03. We expected a new project (web) page. These two SARs are on the page for project 2016-02 which is CIP-002 Transmission Owner Control Centers (TOCC). Project 2016-02 appears to have an approved SAR for TOCC. The two SARs for project 2021-03 do not explicitly address TOCC. There is only one comment form for project 2021-03. How many SDTs are expected (1, 2 or 3)?

Likes 0	
Dislikes 0	
Response	

Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	

The Transmission Planner, Planning Coordinator should not get involved in the CIP-002 standards. As for CIP-014, if there is a reliability issue it should be identified in the planning studies and addressed operationally through the SOLs. As IROLs are Operating limits this should be the responsibility of the RC. Perhaps the answer here is again to expand the scope of CIP-014 to facilities that have an identified IROL, but not the Functional Entities.

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's agreement with EEI's comments and addresses our concerns.

Likes 0	
Dislikes 0	

Response

Justin Kuehne - AEP - 3,5,6

Answer	
Document Name	

Comment

AEP appreciates the efforts of the SDT for this project. No further comments at this time.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

We appreciate the opportunity to comment.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 1 - NPCC	
Answer	
Document Name	
Comment	
If there is a Standard Drafting Team that addresses the IROL question, recommend that SDT include expertise in 1) IROLs and 2) CIP. This posting is confusing. These two SARs are project 2021-03. We expected a new project (web) page. These two SARs are on the page for project 2016-02 which is CIP-002 Transmission Owner Control Centers (TOCC). Project 2016-02 appears to have an approved SAR for TOCC. The two SARs for project 2021-03 do not explicitly address TOCC. There is only one comment form for project 2021-03. How many SDTs are expected (1, 2 or 3)?	
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 Segements 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
The existing NERC CIP Evidence Request Tool already requires entities to provide a discreet asset list of EACMS, PACS, and PCAs. Therefore, adding additional requirements to identify these assets is unnecessary and duplicative to existing requirements.	

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Kendra Buesgens - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	
Document Name	

Comment

The MRO NSRF would like the SAR Drafting Team to consider the following:

- Re-defining EACMS as two separate definitions – Electronic Access Control Systems, and Electronic Access Monitoring Systems (EACS / EAMS). Separating them allows more granularity in the subsequent technical requirements in CIP-007 and CIP-010 (perhaps others).

o The SAR should have "SAR Type" box "Add, Modify or Retire a Glossary Term" checked.

- The identification of these Cyber Assets is already required in order to meet and maintain compliance to CIP-005 and CIP-006. For example, the CIP Evidence Request Tool (ERT) version 6 already includes requests for these types of lists (EACMS & PACs) on the 'Cyber Assets' tab. However, the CIP ERT is not enforceable, so if these types of lists are to be requested, associated clear requirements are necessary.
- The MRO NSRF has concerns about creating a zero-defect requirements.

Likes 0	

Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - NPCC - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
If there is a Standard Drafting Team that addresses the IROL question, recommend that SDT include expertise in 1) IROLs and 2) CIP. This posting is confusing. These two SARs are Project 2021-03. We expected a new project (web) page. These two SARs are on the page for project 2016-02 which is CIP-002 Transmission Owner Control Centers (TOCC). Project 2016-02 appears to have an approved SAR for TOCC. The two SARs for project 2021-03 do not explicitly address TOCC. There is only one comment form for project 2021-03. How many SDTs are expected (1, 2, or 3)?	
Likes 0	
Dislikes 0	
Response	
Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments	
Answer	
Document Name	
Comment	
PG&E has no additional comments.	

Likes 0	
Dislikes 0	

Response

Jennifer Buckman - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	
Document Name	

Comment

The existing NERC CIP Evidence Request Tool already requires entities to provide a discreet asset list of EACMS, PACS, and PCAs. Therefore, adding additional requirements to identify these assets is unnecessary and duplicative to existing requirements.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6

Answer	
Document Name	

Comment

AZPS has no additional comments at this time.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

NA

Likes 0	
Dislikes 0	

Response

Summary Response to Comments

Project 2021-03 CIP-002 | Standard Authorization Request

Project Background

NERC Project 2021-03 CIP-002 currently has five assigned Standard Authorization Requests (SARs). The response to comments is based on the below SARs:

1. CIP-002-5.1a and CIP-014-2 – This SAR provides revisions to CIP-002 and CIP-014 to clarify the responsibility of Reliability Coordinators, Planning Coordinators, and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards. As it relates to the Transmission Planner and Planning Coordinator functions, the language "critical to the derivation of Interconnection Reliability Operating Limits (IROLs)" should be replaced/updated to appropriately identify Facilities that, if somehow compromised, could significantly impact the reliability of the Bulk Electric System (BES). Additionally, this SAR includes a review of the applicability of Facilities identified by the Reliability Coordinator as critical to the derivation of IROLs to CIP-002 and CIP-014. The SC accepted this SAR on July 21, 2021.

2. Modifications to CIP-002 – This SAR seeks to revise CIP-002 to include identification and categorization of certain Cyber Assets (Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets) associated with high and medium impact BES Cyber Systems. The SC accepted this SAR on November 17, 2021.

Based on SAR additions and comments received, the project title has been updated to state "CIP-002" instead of "CIP-002 Transmission Owner Control Center."

SAR Posting

The "Modifications to CIP-002" and "CIP-002-5.1a and CIP-014-2" SARs were posted November 22 through December 21, 2022 for a 30-day informal comment period. All drafting team (DT) responses to the comments are outlined below.

Question 1: Do you agree with the proposed scope as described in the CIP-002 and CIP-014 SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope, please provide your recommendation and explanation.

__Industry Comment:__

A commenter requested the DT provide clarification to the proposed SAR clarifying if this IROL is for identifying sites or systems? It was also recommended that the scope include IROLs that are shared among entities.

Drafting Team Response:

Thank you for your comment. This project provides revisions to CIP-002 and CIP-014 to clarify the responsibility of Reliability Coordinators, Planning Coordinators, and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards. Identifying Facilities is not synonymous with identifying sites. NERC defines a Facility as "A set of electrical equipment that operates as a single BES Element (e.g., a line, a generator, a shunt compensator, transformer, etc.). The DT will look at additional information regarding Facilities and systems.

The DT will take into consideration the changes made to FAC-014 by the Project 2015-09 DT, which initiated the modifications of IROLs.

Industry Comment:

A commenter shared concern that the CIP-002 and CIP-014 IROL SAR is outside the scope of the Planning Coordinator (PC), Transmission Planner (TP), and Reliability Coordinator (RC), and "If Facilities are not being considered in the applicability section of the standard, [then] that should be addressed first. Interconnections which are the responsibility of the owners drives the inclusion in these standards, so the responsibility should be kept there. For the purpose of security owners to have the necessary information to assess the standards, the information necessary to assess does not sit with the PC, TP, or RC, nor should they. If issues exist with a facility and the location, the[n] it should be considered as a contingency and addressed in TPL-001."

Drafting Team Response:

Thank you for your comments, but the DT respectfully disagrees. The Facilities addressed by this SAR as of April 1, 2024, are determined by the RC consistent with FAC-014-3 requirements.

- For CIP-002, the SAR is to clarify the identification of assets integral for the development of IROL(s) and stability limits for elevating associated BES Cyber Systems from low impact to medium impact. Transmission Owners (TOs) do not have the responsibility for identifying IROL(s) or developing stability limits. Entities must rely on communication from their RC to apply criterion 2.6 which determines if IROL(s) are within scope.
- For CIP-014, as of April 1, 2024, IROL(s) are determined by the RC based on the criteria in CIP-002.
- For TPL-001, the objective is to identify system improvements necessary to address certain contingencies within the planning horizon, not informing the owners of generation and transmission Facilities of IROL impacts.

Industry Comment:

A commenter mentioned that this SAR is too vague and not clear on what risk is being addressed. We find no need or added value for the proposed SAR.

Drafting Team Response:

Thank you for your comments, but the DT respectfully disagrees. The CIP-002 and CIP-014 SAR was developed based on industry comments that the Project 2015-09 SDT (Establish and Communicate SOLs) received when proposing changes to the CIP Standards that contain IROL. The main purpose of Project 2015-09 was to retire the planning based IROLs within the respective operating and planning (O&P)

Standards and the CIP Standards. While the team had success with the O&P Standards, industry did not fully agree with removing IROLs from the CIP Standards. To allow the Project 2015-09 SDT to close out their scope of work, a new SAR (2021-03 CIP-002 and CIP-014) was developed and submitted to address the CIP-related recommendation to have planned IROLs removed.

The detailed description of the SAR provides in-depth details that help clarify the purpose. Those items are listed below. Revisions to CIP-002 and CIP-014 to include:

1. Identifying Functional Entities that identify Facilities applicable to CIP-002 and CIP-014.
2. Identifying Functional Entities responsible for the communication of the identified Facilities.
3. Applicability sections to be reviewed and revised accordingly.
4. Determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP’s Planning Assessment for the Near-Term Transmission Planning Horizon.
5. Determine the appropriateness of the identification of Facilities critical to the derivation of IROLs by the RC.

Industry Comments:

Many commenters expressed lack of support the proposed scope for this SAR because it is unclear the reliability gap associated with RC, PC, and TP responsibilities in the identification of critical facilities associated with IROLs. While these registered entities are not identified in CIP-002 or CIP-014 directly, the establishment, identification, and communication of IROLs is already contained in other NERC O&P Reliability Standards. Specifically, during Project 2015-09 (Establish and Communicate System Operating Limits) these obligations were addressed. Adding redundant requirements in CIP-002 and CIP-014 would only add unnecessary and duplicative obligations on registered entities. It is also important to note that the modifications made under Project 2015-09 to address these issues went into effect on April 1, 2024. FAC-014-3, Requirement R5 requires RCs to provide information to PCs, TPs, GOs and TOs (see subparts 5.2 & 5.6) and sub-part R5.6 requires RCs to provide “Each impacted Generator Owner or Transmission Owner, within its Reliability Coordinator Area, with a list of their Facilities that have been identified as critical to the derivation of an IROL and its associated critical contingencies at least once every twelve calendar months.” The concerns expressed in this SAR are unnecessary and would add language to CIP-002 and CIP-014 that would create duplicative Requirements in those Reliability Standards and necessitate adding FAC-014-3 to the project scope in order to make conforming changes to that Reliability Standard. For these reasons, we do not support the proposed SAR.

Drafting Team Response:

Thank you for your comments, but the DT respectfully disagrees. Project 2015-09 identified CIP-002 and CIP-014 for necessary revisions in conjunction with revisions to FAC-014-3 and did attempt to make progress by converging their work along with Project 2016-02. However, this work was pulled back to allow Project 2016-02 to complete the final ballot of CIP-002. This SAR picks up the unfinished objectives of Project 2015-09.

Question 2: Do you agree with the proposed scope as described in the modifications to CIP-002 SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope, please provide your recommendation and explanation.

Industry Comment:

A couple of commenters stated: "We do not feel the scope of this SAR is correct for Transmission Owner Control Centers (TOCC). The proposed SAR modifications dilute the project. If NERC or Industry feels like there needs to be identification of PACS, EACMS, and PCA under CIP-002, then there should be a separate specific project not scope creep on this project. This project's background and purpose have nothing to do with PACS, EACMS or PCAs. Adding this to the SAR will certainly extend this project beyond the timeline established for this project which is not acceptable."

Drafting Team Response:

The SARs associated with this project are separately filed and will be handled by the DT and NERC in a manner that successfully addresses all items in scope for Project 2021-03.

The Standards Committee (SC) authorized the following SARs be assigned to the Project 2021-03 DT:

- 2016-02 (TOCC Part of the SAR[1])
- CIP-002 and CIP-014 IROL SAR
- CIP-002 (EACMS, PACS, and PCAs)
- CIP-002 Communications Protocol Converters SAR
- CIP-002-5.1a Criterion 1.3 Revision SAR

NERC solicited for additional nominations from May 23, 2022 – June 22, 2022, and from July 20, 2023 – August 18, 2023, to supplement the DT members to provide additional members in addressing the additional SARs assigned to this team. NERC staff split this project into Group A and Group B. All SARs are under the same project as assigned by the DT; however, the team members who are unable to participate in the additional SARs remain on Group A and all other DT members plus the additional DT members are on Group B. The new DT members are not in Group A as that SAR has confidentiality agreements, and the project was too far along to add those additional members to Group A. Below lists out the assignments of each SAR to the respective Group.

- Group A:
    - 2016-02 SAR (TOCC part of the SAR)
- Group B:

[1] Language pulled directly from the 2016-02 SAR that pertains to the TOCC portion that was assigned to Project 2021-03
• Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations –
V5TAG is aware of multiple interpretations of the language "used to perform the functional obligation of" in CIP-002-5.1 Attachment 1, section 2.12 and recommends clarification of:
• The applicability of requirements on a TO Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
• The definition of Control Center.
• The language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.

- CIP-002 and CIP-014 (IROL)
- CIP-002 (EACMS, PACS, and PCA)
- CIP-002 Communications Protocol Converters SAR
- CIP-002-5.1a Criterion 1.3 Revision SAR

Lastly, to address any confusion on the name of the project, Project 2021-03 has been updated from "Project 2021-03 TOCC" to "Project 2021-03 CIP-002.

Industry Comment:

Many commenters supported the following: "it is unclear the reliability gap that this SAR intends to close. While it is clear that responsible entities under CIP-002 must identify BES Cyber Systems and their associated BES Cyber assets, the current standard does not implicitly require the development of a list of those assets. This is because lists do not guarantee assets are protected. Moreover, administratively, mistakes in documentation can happen even when affected assets have been identified and properly protected. Additionally, this SAR proposes to move CIP-002 away from a Risk-Based standard to one that is a zero-defect standard which does little to improve BES Reliability, while creating a significant compliance burden and risk for responsible entities.

It is also worth considering whether the formal development of discrete lists of Cyber Assets is a forward-looking approach that will last as technology evolves. While over the life of the CIP standards, electronic access control has and will continue to morph from dedicated Cyber Assets (i.e., a discrete HW firewall, a discrete HW domain controller server, etc.) to a function performed in ever more distributed ways. Zero Trust principles may affect access policies. Zero Trust could also result in thousands of logical ESPs around sessions, and thus thousands of EACMS. The concept of EACMS as a discrete 'Cyber Asset' that you can be put on a list will lose meaning over time, rendering a standard obsolete. The technology is headed to electronic access control being a highly distributed function enforced throughout the infrastructure, not a list of dedicated Cyber Assets.

It is also worth noting that virtualization is abstracting 'programmable electronic devices' into a generic hardware resource pool, on top of which many functions are implemented. It is our understanding that the Project 2016-02 SDT is working to incorporate into the PCA definition not only the sharing of a local network, but the sharing of a hypervisor's CPU and memory resources. This type of change will result in dynamic system operation, with a virtual machine becoming a PCA based on where it is executing at the moment. Such a scenario will make the development of discrete lists of categorized BES Cyber Assets nearly impossible, possibly rendering the proposed changes obsolete before the Reliability Standard ever become enforceable."

Drafting Team Response:

Thank you for your comments. The DT agrees that the SAR is unclear and proposed edits have been incorporated. Auditors addressing missed identification of EACMS, PACS, and PCAs have found it difficult to keep potential findings of non-compliance relegated to a single standard for each finding. The intent of the SAR is to address this in a single standard to handle each case where failure to identify and provide appropriate protections has occurred.

The DT agrees with your comment regarding static cyber assets versus distributed functions. The SAR has been revised away from “Cyber Asset” identification and is now focused on systems and protected cyber assets.

Industry Comment:
One commenter stated: “the creation of a discrete list of Cyber Asset for [EACMS, PACS, and PCA] is going to be more difficult as virtualization expands within the industry. This will be especially true for EACMS as the firewall and access point move from specific devices to potentially every Cyber Asset. The SAR should be modified to address these trends so it does not restrict what a drafting team can do to satisfy NERC’s desire to make sure all BCS associated Cyber Assets are identified and appropriately protected.”

Drafting Team Response:
Thank you for your comment. The SAR has been revised to reflect your comment in that focuses on the systems performing the protective objectives for EACMS, PACS, and PCAs and not the discrete cyber assets that’s located in a single location.

Industry Comment:
Several commenters stated this gap should not be addressed in CIP-002 as it would be better addressed in other CIP standards. “The ESP and PSP concepts are not relevant for the assessment performed in regard to the CIP-002 standard, nor EACMS, PCA, and PACS. Bringing these types of cyber assets and concepts into the scope of CIP-002 brings an undesirable burden on demonstrating compliance with the CIP-002 standard and would require even more multidisciplinary expertise to perform the assessment.
This gap should be filled in CIP standards that already address these concepts and types of cyber assets.

Recommend including Glossary changes to support this SAR.

Please consider the identification of 1) assets in the cloud, and 2) third-party cyber assets.

Request use cases for cyber assets a) on-site entity owned, b) on-site third party owned, c) off-site entity owned and d) off-site third-party owned. And conforming changes in the rest of the CIP Standards.

Request addressing other CIP-002 gaps like the threshold for new assets which have no prior history. Some existing thresholds depend on the prior year’s information.”

Drafting Team Response:
Thank you for your comments. The DT considered expansion of scope to other CIP standards but agreed that CIP-002 was best suited to address the objectives of the SAR. Further, the SAR has been revised and reflects your comment that the focus is not the discrete cyber assets that’s located in a single location but rather pertinent to systems performing the protective objectives for EACMS, PACS, PCAS. The SAR provides latitude for the DT to consider off-site/third party owned. Additionally, the DT will take into consideration your comment during standards drafting.

Industry Comment:

A couple of commenters stated: "if adding PACS, PCA, and EACMS to the scope of CIP-002 then those should be updated as a part of Project 2016-02 as there are new Cyber Assets coming into scope under that project or make this a project post [for] Project 2016-02 approval. Further if as an industry we add to CIP-002's scope, not making this change as a part of 2016-02 will require programmatic changes again in the near future for the new asset and sub asset types creating increased and unnecessary compliance burden."

Drafting Team Response:

Thank you for your comments, but the DT respectfully disagrees. The DT will keep this SAR as assigned by the Standards Committee and will take into consideration your comment during standards drafting.

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

Industry Comment:

A commenter asked is there a Standard Drafting Team that addresses the IROL question, recommend that SDT include expertise in 1) IROLs and 2) CIP. This posting is confusing. These two SARs are project 2021-03. We expected a new project (web) page. These two SARs are on the page for project 2016-02 which is CIP-002 Transmission Owner Control Centers (TOCC). Project 2016-02 appears to have an approved SAR for TOCC. The two SARs for project 2021-03 do not explicitly address TOCC. There is only one comment form for project 2021-03. How many SDTs are expected (1, 2 or 3)?

Drafting Team Response:

Thank you for your comment. This DT is not conducting an assessment on the appropriateness of the IROL determination, but merely whether or not an IROL determination has been made. If it has, then that result can impact the assessment for TOCC applicability. In that other standards would be the determining factor for the declaration of an IROL, we will rely on those DT teams to appropriately defined the application for such an operating limit. The revisions to CIP-002 and CIP-014 will clarify the responsibility of Reliability Coordinators, Planning Coordinators, and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards.

The Standards Committee (SC) authorized the following SARs be assigned to the Project 2021-03 SDT:

- 2016-02 (TOCC Part of the SAR[2])
- CIP-002 and CIP-014 IROL SAR
- CIP-002 (EACMS, PACS, and PCAs)
- CIP-002 Communications Protocol Converters SAR

[2] Language pulled directly from the 2016-02 SAR that pertains to the TOCC portion that was assigned to Project 2021-03
• Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations –
V5TAG is aware of multiple interpretations of the language "used to perform the functional obligation of" in CIP-002-5.1 Attachment 1, section 2.12 and recommends clarification of:
• The applicability of requirements on a TO Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers and relays in the BES.
• The definition of Control Center.
• The language scope of "perform the functional obligations of" throughout the Attachment 1 criteria. •

- CIP-002-5.1a Criterion 1.3 Revision SAR

NERC solicited for additional nominations from May 23, 2022 – June 22, 2022, and from July 20, 2023 – August 18, 2023 to supplement the DT members to provide additional members in addressing the additional SARs assigned to this team.

Industry Comment:
One commenter stated that the Transmission Planner and Planning Coordinator should not get involved in the CIP-002 standards. As for CIP-014, if there is a reliability issue it should be identified in the planning studies and addressed operationally through the SOLs. As IROLs are Operating limits this should be the responsibility of the RC. Perhaps the answer here is again to expand the scope of CIP-014 to facilities that have an identified IROL, but not the Functional Entities.

Drafting Team Response:
Thank you for your comment, but the DT respectfully disagrees. The DT does not feel that it is within our scope to make any determinations on how operating limits are established. If the operating limit is established, then that determination can have a bearing on the responsible entity's application of their CIP-002 assessment.

Industry Comment:
The MRO NSRF would like the SAR Drafting Team to consider the following:

- Re-defining EACMS as two separate definitions – Electronic Access Control Systems, and Electronic Access Monitoring Systems (EACS / EAMS). Separating them allows more granularity in the subsequent technical requirements in CIP-007 and CIP-010 (perhaps others). o
- The SAR should have "SAR Type" box "Add, Modify or Retire a Glossary Term" checked.
- The identification of these Cyber Assets is already required in order to meet and maintain compliance to CIP-005 and CIP-006. For example, the CIP Evidence Request Tool (ERT) version 6 already includes requests for these types of lists (EACMS & PACs) on the 'Cyber Assets' tab. However, the CIP ERT is not enforceable, so if these types of lists are to be requested, associated clear requirements are necessary.
- The MRO NSRF has concerns about creating a zero-defect requirements.

Drafting Team Response:

Thank you for your comment. Although splitting of EACMS into two separate items may have merit, expanding this SAR to accommodate an EACMS split goes beyond its scope and purpose. An EACMS split request should be submitted via a new SAR.

The DT determined the SAR is unclear regarding identification of EACMS, PACS, and PCAs and proposed edits have been incorporated. Auditors addressing missed identification of EACMS, PACS, and PCAs have found it difficult to keep potential findings of non-compliance relegated to a single standard for each finding. The intent of the SAR is to address this in a single standard to handle each case where failure to identify and provide appropriate protections has occurred. Further, revisions to the SAR have also been made to avoid mandating creation of zero-defect requirements.

Industry Comment:

The existing NERC CIP Evidence Request Tool already requires entities to provide a discreet asset list of EACMS, PACS, and PCAs. Therefore, adding additional requirements to identify these assets is unnecessary and duplicative to existing requirements.

Drafting Team Response:

Thank you for your comment, but the DT respectfully disagrees. The NERC CIP Evidence Request is an auditing tool outside of standard requirements. The objective of the SAR is not to incorporate audit processes into a standard or requirement but to address the identification of EACMS, PACS, and PCAs.

Industry Comment:

Several companies were thankful for the opportunity to respond and the SDT efforts.

Drafting Team Response:

Thank you for your comments.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

NERC Project 2021-03

CIP-002 Transmission Owner Control Center Field Test Final Report

January 2023

RELIABILITY | RESILIENCE | SECURITY

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Table of Contents

Executive Summary

The CIP-002 Transmission Owner Control Centers (TOCC) standard drafting team (SDT) was formed to further evaluate the adequacy of CIP-002-5.1a, Attachment 1, Criterion 2.12, in respect to identifying Control Centers used to perform the functional obligations of the Transmission Operator (TOP) that are not otherwise included in high impact rating.

The SDT developed a TOCC Field Test including a series of questionnaires provided to the participants with the ultimate intention of determining whether there is adequate technical justification to modify CIP-002 such that BES Cyber Assets at TOP and TOCCs can be classified as low impact without exposing the BES to unacceptable increased risk.

The SDT analyzed 22 responses, from 20 active and 2 withdrawn participants who provided relevant information prior to withdrawal.

After reviewing the Field Test responses, the SDT believes that there are entities for which the constraints associated with medium impact rating categorization are not commensurate with the risk posed to the BES should their Control Center be compromised. Based on the results of the Field Test, it may be appropriate to incorporate additional inclusion characteristics into the Criterion 2.12 and the previously proposed aggregate weighted value. Such inclusion characteristics include control of Transmission Facilities associated with a major interface or Blackstart Resources and initial Cranking Paths. Further, it may also be appropriate to incorporate exclusion criteria, recognizing that some Control Centers whose aggregate weighted value of lines exceeds 6000 may have a negligible impact on the reliability of the BES, if compromised.

Introduction

On May 14, 2020, the NERC Board of Trustees (Board) adopted proposed Reliability Standard CIP-002-6. The proposed Reliability Standard revised Criterion 2.12 to clarify the characterization of BES Cyber Systems associated with Control Centers used to perform the functional obligations of the TOP. This revision was intended to clarify the language "used to perform the functional obligation of" in the current Reliability Standard and recognize the existence of certain TOCCs performing TOP reliability functions as medium impact based on an aggregate weighted value of their Transmission Lines. The revision also recognized the existence of registered TOP entity Control Centers that could be categorized as low impact based on having minimal impact to the BES, if compromised. The Standards Committee accepted the Project 2016-02 standard authorization request on July 20, 2016[1], which includes the scope for addressing the TOCC obligations.

On June 12, 2020[2], NERC staff filed with the Federal Energy Regulatory Commission (FERC) a petition for approval of proposed CIP-002-6. NERC filed the Reliability Standard on June 23, 2020, with the applicable regulatory authorities in Canada.

At the February 4, 2021[3] meeting, the Board withdrew proposed Reliability Standard CIP-002-6 and issued a resolution stating, "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers to safeguard reliability, for the purpose of recommending further action to the Board." On February 5, 2021[4], NERC filed a notice of withdrawal for CIP-002-6 with FERC. The 2021-03 CIP-002 TOCC SDT was formed to conduct further study and recommend next steps, in response to the following SAR language:

"Transmission Owner (TO) Control Centers Performing TOP Obligations – V5TAG is aware of multiple interpretations of the language "used to perform the functional obligation of" in CIP-002-5.1 Attachment 1, section 2.12 and recommends clarification of:

- The applicability of requirements on a TO Control Center that performs the functional obligations of a TOP, particularly if the TO has the ability to operate switches, breakers, and relays in the BES.
- The definition of Control Center.
- The language scope of "perform the functional obligations of" throughout the Attachment 1 criteria."

The SDT designed a Field Test to obtain data from TOs and TOPs to validate the proposed bright line Criterion 2.12, and not expose the BES to unacceptable increased risk. TOPs were included in the Field Test given that any modifications to Criterion 2.12 will affect all entities who perform the functional obligations of the TOP (inclusive of TOPs and a subset of TOs). The SDT recognizes the TOs' need for further clarification to identify if they operate a control room that qualifies as a Control Center used to perform the reliability tasks of a TOP.

The possible outcomes of this Field Test would be to recommend the next steps with respect to Criterion 2.12:

1. Retain the current bright line Criterion 2.12 language (shown below);
2. The proposed bright line Criterion 2.12 language (shown below) remains justified with additional technical basis; or
3. Recommend a new bright line Criterion 2.12 based on the technical results obtained from the Field Test.

[1] Standards Committee meeting minutes – July 20, 2016 link: Standards Committee Meeting Minutes - Approved July 20, 2016.pdf (nerc.com)
[2] CIP-002-6 Petition Filing with FERC link: Petition_for_Approval_CIP-002-6_packaged.pdf (nerc.com)
[3] NERC Board meeting minutes – February 4, 2021 link: 0_MRC-Informational-Session-Agenda-04-15-20 (nerc.com)
[4] NERC Petition to FERC requesting withdraw of CIP-002-6 link: Notice of Withdrawal CIP-002-6 (nerc.com)

CIP-002-5.1a, Attachment 1, Section 2 provides medium impact rating criteria for each BES Cyber System that is not included in the high impact rating criteria of Section 1.

1. Current Criterion 2.12 states:
   Each Control Center or backup Control Center used to perform the functional obligations of a Transmission Operator not included in high impact rating.
2. Proposed bright line Criterion 2.12 from the withdrawn CIP-002-6:
   Each Control Center or backup Control Center, not included in the high impact rating, used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines with an "aggregated weighted value" exceeding 6000 according to the table below. The "aggregated weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

.Voltage Value of a Line	Weight Value per Line
less than 100 kV (not applicable)	(Not applicable)
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

Chapter 1: Field Test Questionnaires

The TOCC Field Test included a series of questionnaires provided to the participants to determine whether there is adequate technical justification to modify CIP-002 such that BES Cyber Assets at TOP and TOCCs can be classified as low impact without exposing the BES to unacceptable increased risk. The SDT included questions specifically intended to determine if Field Test participants have a common understanding of Capability to Operate versus Authority to Operate with respect to performing the functional obligations of a TOP where the capitalized terms, not included in the NERC Glossary of Terms, are defined in questionnaire 2. Attachment 1 contains the questionnaires.

The SDT designed questionnaire 1 to obtain a range of inherent attributes from each participant. This data aided in mapping out the bookends of participating companies and was referenced throughout as an approximate gauge of potential level of impact to the BES. Additional questionnaires were developed to advance the SDT's understanding of the potential BES response to a variety of cyber-attacks levied against the individual Control Centers.

Questionnaire 2 asked participants to provide additional information and to perform detailed steady-state power flow studies. These included specific cyber events to identify any adverse impact to BES reliability: scenario instability, uncontrolled separation, or Cascading. The questionnaire provides study case assumptions and additional details. The following three event scenarios were requested:

- All breakers/switches that can be operated remotely from the entity's BES Cyber System are simultaneously opened
- All lines and autotransformers which an entity is capable of interrupting through-flow from the entity's BES Cyber System are operated sequentially
- Study a broad range of system conditions following a wider range of probable Contingencies as identified in TPL-001-5.1

Questionnaire 3 asked participants to verify aspects of the participant's system and neighboring connections. Many of the questions intended to query for characteristics identified by the SDT as potential indicators of systems that, if compromised, would be considered as having additional risk to the BES.

Chapter 2: Outreach

Parallel to the Field Test described above, the SDT performed an analysis of NERC-registered TOs and TOPs to develop a better understanding of the population of entities that could be impacted by a modification to the bright line Criterion 2.12 language. This analysis included 347 unique entities, some of which are under the jurisdiction of multiple Regional Compliance Enforcement Authorities.

Of the 347 entities, the SDT identified 231 (or 67%) who are not expected to be impacted by any modifications to Criterion 2.12.

There were 190 of these entities screened out of the data set based on SDT member knowledge. The screening was performed on the list of NERC-registered TOs and TOPs to allow the SDT to focus outreach efforts on the entities most likely impacted by changes to Criterion 2.12.

Justification for screening out entities included the following:

- Entity registered as a Reliability Coordinator and categorized as high impact rating under Criterion 1.1.
- Entity operates 500kV+ assets and categorized as high impact rating under Criteria 2.4 and 1.3.
- Entity operates multiple major stations and would be categorized as high impact rating under Criteria 2.5 and 1.3
- Entity is registered as a TO and does not have the capability to operate BES Elements via a BES Cyber System.

The remaining 41 entities, not expected to be impacted by any modifications to Criterion 2.12, were classified as such following contact by SDT members.

SDT members were able to contact 37 of the remaining 116 entities to confirm that they would likely be impacted by a modification to the bright line Criterion 2.12 language. These 37 entities include all of the entities that are active in the Field Test. Some entities expressed interest in the Field Test but were unable to join due to time and resource constraints. Other entities elected not to participate in the Field Test for undisclosed reasons. The SDT was unable to contact the remaining 79 entities.

Chapter 3: Field Test Response Summary

Thirty-three entities expressed interest in participating in the Field Test. One of the entities represented five separate Field Test participants. Thus, there were thirty-seven participants considered during the Field Test.

Five participants expressed tentative interest but were unable to provide the SDT with any data. Further, ten participants provided some data but withdrew from the Field Test early. The participants' reasons for withdrawal included:

- The location was not relevant to the Field Test (i.e., the location does not meet the definition of a Control Center as defined in the NERC Glossary of Terms);
- Changes were in progress to modify the location such that it no longer meets the definition of a Control Center as defined in the NERC Glossary of Terms; or
- The entity representing the location did not have the time and/or resources to continue in the Field Test.

The SDT reviewed the data provided by withdrawn participants. Based on this, partial responses from 2 of the 10 withdrawn participants were included in the results.

Further, the SDT classified two participants who remained engaged throughout the entirety of the Field Test as not relevant to the results. Based on the review of responses, it was determined that neither participant has a BES Cyber System (e.g., SCADA system) with the capability to operate BES Elements. For both participants, a third-party TOP has the sole capability to operate equipment in normal and emergency conditions. Thus, neither participant meets the definition of a Control Center as defined in the NERC Glossary of Terms. The SDT excluded responses from these two participants.

The SDT analyzed 22 responses, from 20 active and 2 withdrawn participants who provided relevant information prior to withdrawal.

Summary of Participant Characteristics

The following section provides an overview of the characteristics of the 22 participants that the SDT evaluated. Out of the 22, 5 participants are registered as both TOP and TO, and 17 are registered as TO only.

One of the participants was a data center with no capability to control BES Elements. As such, its aggregate weighted value of lines as calculated using the proposed bright line Criterion 2.12 from the withdrawn CIP-002-6 is zero. The participant sends data from stations to a third-party TOP. Further discussion related to the inclusion of 'data center' in the Control Center definition is in Chapter 4 of this document.

The remaining 21 participants represent facilities that host operating personnel to monitor and control the BES in real-time to perform the reliability tasks of a TOP for transmission Facilities at 2 or more locations. The aggregate weighted value of lines as calculated using the proposed bright line Criterion 2.12 from the withdrawn CIP-002-6 for these 21 participants ranges from 500 to 11,300. Four participants exceed the previously proposed bright line threshold of 6,000. The remaining 17 participants fell at or below 6,000.

In addition, the SDT queried the 21 participants (excluding the data center) on the following:

- Peak load served from 1/1/2020 through 10/1/2021 that could be interrupted remotely
- Total capacity of conventional BES generation Facilities that could be interrupted remotely
- Total capacity of intermittent (e.g., wind, solar) BES generation Facilities that could be interrupted remotely

The peak load served from 1/1/2020 through 10/1/2021 that participants can interrupt remotely varies from zero MW to 1,300 MW. Six participants identified more than 400 MW of load. Another seven participants identified more than 100 MW of load. The remaining eight participants identified less than 100 MW of load.

Eleven participants self-identified as serving no BES generation Facilities. Ten participants identified conventional BES generation Facilities that could be interrupted remotely with capacities ranging from 52 MW to 235 MW. This includes some run-of-the-river hydro generation generally not considered dispatchable, as there is little or no water storage available. One participant identified an interconnected intermittent BES generation Facility with a capacity less than 20 MW.

The participants did not identify any of following:

- CIP-002-5.1a Criteria 2.2, 2.4, 2.5, 2.7, 2.8, 2.9 or 2.10 that would otherwise elevate the BES Cyber Systems associated with the Control Center to high impact rating.
- BES Elements that have been identified by a Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.
- BES Elements that are included as a monitored element or an operated element for any Remedial Action Scheme (RAS).
- BES Elements providing the generation interconnection required to connect BES generator resources output equal to or greater than an aggregate of 1500 MW that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation resource to interconnected neighbors.
- BES Elements that are critical to system restoration associated with Blackstart Resources or included in the Cranking Path and initial switching requirement of any TOP’s restoration plan.

Participants were also queried on BES Elements that are included as part of an interface that has been defined as a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or comparable interface in the ERCOT Interconnection (e.g., generic transmission constraint), the Quebec Interconnection, or any contingencies or prior outages associated with any of the prior described interfaces.

One of the participants identified that a Transmission Line within their system is included within the monitored portion of an interface. This participant has an aggregate weighted value of lines as calculated using the proposed bright line Criterion 2.12 from the withdrawn CIP-002-6 of 6,000. No other interfaces, or associated contingencies or prior outages were identified.

Field Test Participant Risk Assessment

The SDT performed a risk assessment of each participant considering its role in area reliability, and to identify if loss of load, generation, or BES Elements within the participant's control area could adversely impact neighboring BES. Participants were requested to respond to three power flow scenarios to quantify this impact.

Of the 22 participants, the SDT analyzed complete power flow scenario responses for 17 and a partial response (third scenario only) for an additional participant:

- No responses received from the two withdrawn participants that were included in the analysis; however, the SDT did receive sufficient information from those two participants as a basis for inclusion in the results.
- One of the active participants was unable to provide a response; however, that participant also provided adequate documentation to serve as a basis for inclusion in the results.
- No response received from the data center described above, given that no BES Elements are controlled from the data center.

The following summarizes the study results:

Power Flow Scenario One: This scenario evaluated impacts to neighboring BES of simultaneously opening the participant's breakers and switches controlled by the participant's BES Cyber Systems. Fourteen of the seventeen participants did not identify any voltage or thermal exceedances during their simulations. For these participants, the extent of system impact was loss of load and/or generation.

For the remaining three participants:

- Two documented minor high voltages caused by locking reactive devices in the power flow. After allowing capacitor banks to be switched out of service, all voltages returned to within the normal range.
- The remaining participant documented multiple internal low voltages, one minor external low voltage and two external thermal exceedances. All of these instances attributed to the study method in which BES Elements, controlled via a BES Cyber System, simultaneously opened while leaving non-BES devices with SCADA-control closed. All internal issues were resolved by disconnecting the non-BES load. All external issues were resolved by an external entity operating its own equipment to disconnect non-BES load.

Power Flow Scenario Two: This scenario evaluated the impact of sequential tripping of heavily loaded elements to identify thermal or voltage exceedances that may cause instability, uncontrolled separation, or cascading to neighboring BES. Nine of the seventeen participants who provided results for this scenario did not identify any voltage or thermal exceedances. For these participants, the extent of system impact was loss of load and/or generation.

For the remaining eight participants:

- Seven participants documented internal exceedances. These participants did not identify instances of instability, uncontrolled separation, or cascading to neighboring BES. In each of these cases, a comparison to the results from the first power flow scenario indicates that complete disconnection of the participant's breakers and switches, controlled by a BES Cyber System, would resolve the issues. Capacitor adjustments would be required by two of the participants based on minor high voltages that the participants identified in the first power flow scenario. Further, the BES Elements controlled by each of these seven participants are connected to their neighbors in such a way that their neighbors would be able to disconnect the participants' BES and prevent adverse impacts to neighboring BES.

- One participant documented various internal voltage and thermal exceedances related to the inability for a non-BES system to support load when cut off from the BES, as described in the first power flow scenario. Internal load shed was effectively used to mitigate all issues. No issues identified in the external system.

Power Flow Scenario Three: This scenario allowed participants to consider a broad range of system conditions following a wide range of probable Contingencies. Eight of the eighteen participants who provided results for power flow scenario three did not identify voltage or thermal exceedances during their simulations.

For the remaining ten participants:

- Eight participants documented internal exceedances. The participants did not identify instances of instability, uncontrolled separation, or cascading to neighboring BES. In general, the internal issues identified appear to be situations where contingencies leave load, in many cases non-BES load, connected to a system with insufficient sources to serve the load. This results in local issues that do not affect the neighboring BES.
- Two participants performed extensive contingency analysis, including a large number of external Contingencies. Each of these participants reported various voltage and thermal exceedances; however, no instability, uncontrolled separation, or cascading was identified. Further, external Contingencies that create external exceedances should not be a factor when evaluating the risk to the BES of any Control Center whose BES Cyber Systems are compromised.

Field Test Conclusions

After reviewing the Field Test responses, as summarized above, the SDT believes that there are entities for which the constraints associated with medium impact rating categorization are not commensurate with the risk posed to the BES should their Control Center be compromised. Of the twenty-two participants evaluated during the Field Test, the SDT did not identify any characteristics or power flow responses for twenty-one of the participants that indicated adverse impact to the BES. Further, the power flow responses for the remaining participant did not indicate adverse impact to the BES; however, the SDT did identify that a Transmission Line operated by this participant is included within the monitored portion of an interface, which may indicate a higher level of impact to the BES should the associated BES Cyber Assets be compromised. The aggregated weighted value of lines for this participant is 6000.

This leads the SDT to believe that it is be appropriate to incorporate additional inclusion characteristics into the Criterion 2.12 in addition to the previously proposed aggregate weighted value. Such characteristics include control of Transmission Facilities associated with a major interface or Blackstart Resources and initial Cranking Paths. Further, it may also be appropriate to incorporate exclusion criteria, recognizing that some Control Centers whose aggregate weighted value of lines exceeds 6000 may have a negligible impact on the reliability of the BES.

The SDT believes that the previously proposed bright line of 6000 remains an appropriate initial criterion to differentiate between low impact and medium impact BES Cyber Systems, when paired with an appropriate inclusion and exclusion criteria. The threshold of 6,000 is based on doubling the aggregate weighted value of 3,000 established in Criterion 2.5[5] of CIP-002-5.1a. This threshold ensures that BES Cyber Systems that monitor and control BES Transmission Lines equivalent to two stations with medium impact BES Cyber Systems will be designated as medium impact, subject to any exclusions.

[5] Criterion 2.5 of CIP-002-5.1a only includes Transmission Lines above 200kV when calculating the aggregate weighted value for the purpose of classifying BES Cyber Systems associated with Transmission stations or substations as medium impact; however, the proposed Criterion 2.12 includes Transmission Lines above 100kV when calculating the aggregate weighted value for the purpose of classifying BES Cyber Systems associated with Control Centers as medium impact. This supports the need for an exclusions process to be added to a future Criterion 2.12.

Chapter 4: Control Center Definition

During the recruitment of TO entities to participate in the Field Test and during the review of Field Test responses, the SDT found that many TOs have struggled to interpret the Control Center definition. This has surfaced in the following three manners:

- Lack of a common understanding of the term ‘control’ versus ‘authority’.
- Lack of a common understanding of the term ‘perform the functional obligations of the TOP’.
- Lack of a common understanding of the term ‘associated data centers’.

The NERC Glossary of Terms defines a Control Center as “One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.”

Control versus Authority/Performing the Functional Obligations of the TOP

Per the Rules of Procedures, every BES Transmission Facility is required to have a registered TO and registered TOP. In many cases, the registered TO acquires a registered TOP for their BES Elements via a contract or agreement. While reviewing Field Test responses, the SDT observed that some TOs indicated that they do not have a Control Center because they are not registered as a TOP and lack the authority to operate BES Elements. Industry needs clarification that the key element for inclusion into the Control Center definition for TOs and TOPs is the capability to control BES Elements, independent of the authority to control BES Elements. Any proposed changes to the Control Center definition will need to be reviewed to evaluate potential impacts to other registered entities.

Associated Data Centers

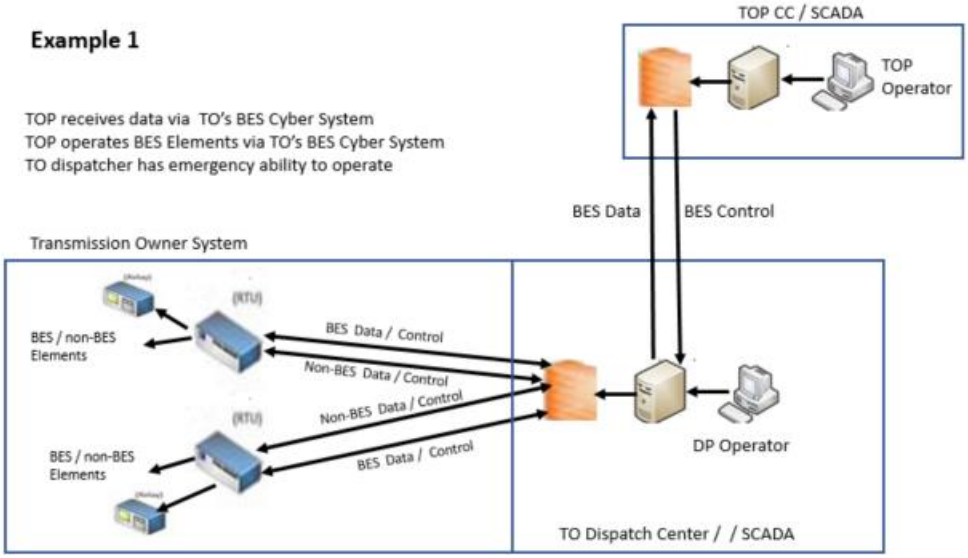
In addition, the SDT observed a lack of clarity regarding the application of the Control Center definition to locations where cyber assets are not associated with control of BES Elements but rather are used to aggregate data for the TOP at unmanned sites. This is in contrast to the original inclusion of ‘associated data centers’ in the Control Center definition to ensure that all SCADA systems that can control BES transmission Facilities be considered a data center, for the TO Control Center or an associated data center of their contracted TOP.

Based on observation during the Field Test, the SDT recommends modifications to the definition of a Control Center to provide clarity on the meaning of associated data centers.

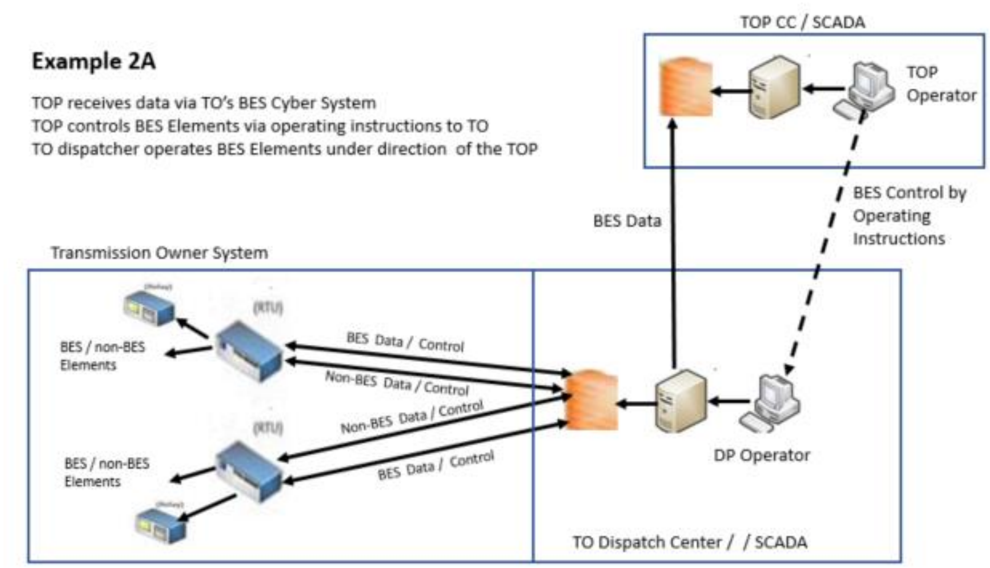
Appendix A: TO/TOP Configurations

The SDT provides the following six TO/TOP configurations to monitor and control BES transmission Facilities. An interpretation, regarding application of the Control Center definition to aid with drafting language that alleviates the opportunity for ambiguity, is provided for each configuration. These may not be inclusive of all existing TO/TOP configurations.

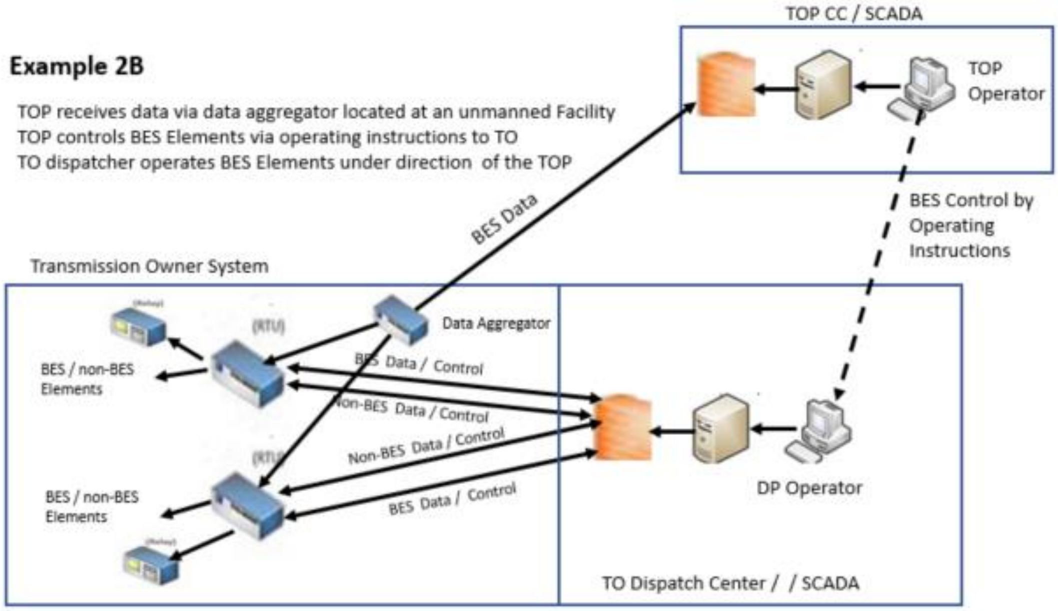
Example 1: TO BES Cyber System should be considered a data center used by the TO to monitor and control BES Elements in real-time to perform the reliability tasks of the TOP. In this model, the TO Dispatch Center should be considered a TO Control Center due to having the capability to control BES Elements.



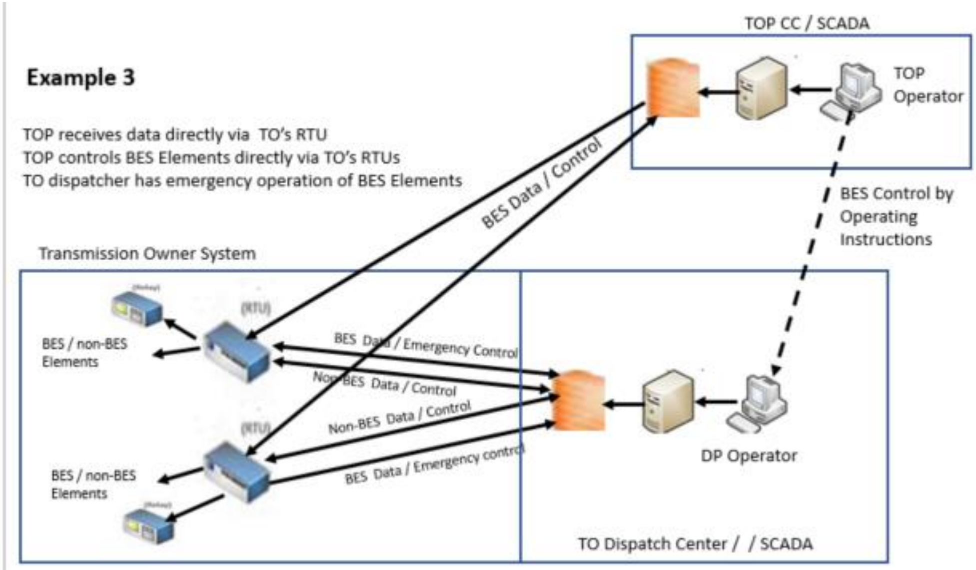
Example 2A: TO BES Cyber System should be considered a data center used by the TO to monitor and control BES Elements in real-time to perform the reliability tasks of the TOP. In this model, the TO Dispatch Center should be considered a TO Control Center due to having the capability to control BES Elements.



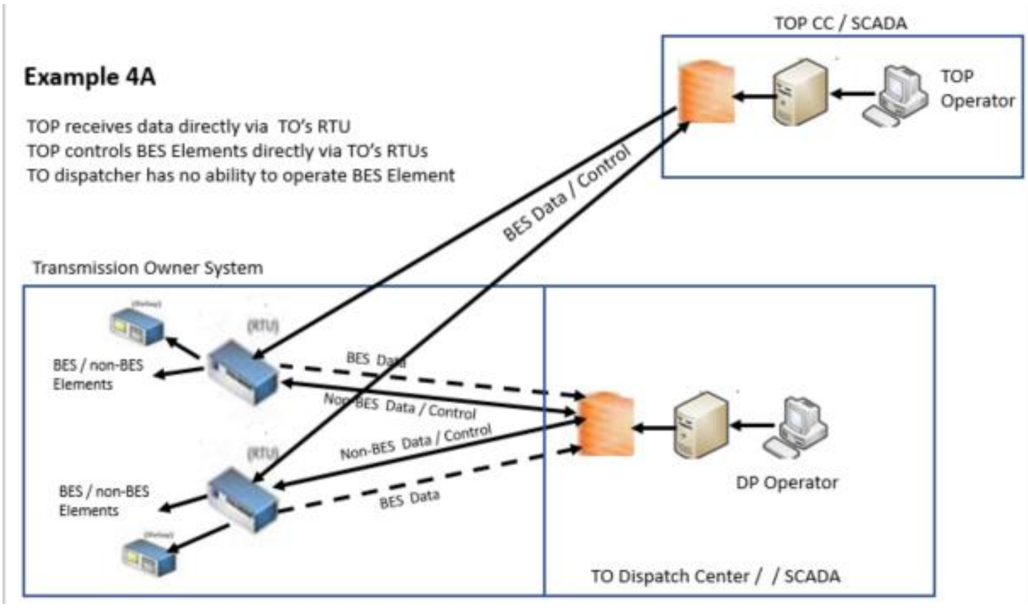
Example 2B: TO BES Cyber System should be considered a data center used by the TO to monitor and control BES Elements in real-time to perform the reliability tasks of the TOP. In this model, the TO Dispatch Center should be considered a TO Control Center due to having the capability to control BES Elements.



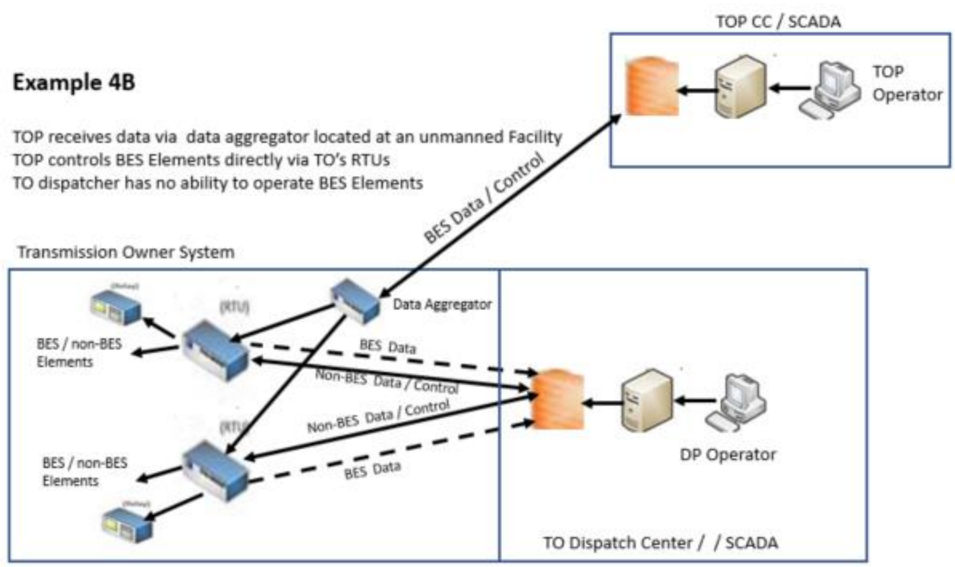
Example 3: TO BES Cyber System should be considered a data center used by the TO to monitor and control BES Elements in real-time to perform the reliability tasks of the TOP in an emergency. In this model, the TO Dispatch Center should be considered a TO Control Center due to having the capability to control BES Elements.



Example 4A: TO BES Cyber System should not be considered a data center because it is not used by the TO to monitor and control BES Elements. In this model, the TO Dispatch Center should not be considered a TO Control Center due to not having the capability to control BES Elements.



Example 4B: TO BES Cyber System should not be considered a data center because it is not used by the TO to monitor and control BES Elements. In this model, the TO Dispatch Center should not be considered a TO Control Center due to not having the capability to control BES Elements.



Attachment 1: Field Test Questionnaire One

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CIP-002 Transmission Owner Control Centers (TOCCs) Field Test Questionnaire

Project 2021-03

Please complete the following questions to help us better understand your system.

As a NERC Control Center is applicable to specific configurations, an entity may have no CC, may have one, or could possibly have multiple CC locations. To the extent that an entity has multiple CC locations that control different Facilities, the entity should complete a separate questionnaire for each CC location or clearly delineate between each CC location on the questionnaire as the individual outcomes of the application of Criterion 2.12 could be different.

1. NERC Registration (e.g., RC/BA/TO/TOP/DP/etc.): ______________________________
2. Do you have a site that is staffed by operating personnel, from which you can remotely operate Facilities at two or more locations?

   ☐ Yes ☐ No

3. Based on the impact to the BES of a cyber event in your footprint, do you believe the site(s) referenced in Question 2 should be low impact, medium impact or high impact? Why?

   ____
   ____
   ____
   ____
   ____
   ____
   ____
   ____
   ____

4. What was the peak load served by your system for the period 1/1/2020 – 10/1/2021, which could be interrupted remotely from the site referenced in Question 2?

   ____

5. What is the total capacity of conventional BES generation Facilities connected to your system, which could be interrupted remotely from the site referenced in Question 2?

   ____

6. What is the total capacity of intermittent (e.g., wind, solar) BES generation Facilities connected to your system, which could be interrupted remotely from the site referenced in Question 2?

   ____

Answer all of the following questions for each location for which the response to Question 2 was "yes".

7. Is there external connectivity to any BES Cyber Asset(s) housed at the site(s) referenced in Question 2? If so, please provide access means for each connection (e.g., dial-up, internet, VPN).

   ☐ Yes ☐ No Access means: ______________________________

8. Do third parties have direct communications access for change management activities associated with BES Cyber Assets or other managed service provider purposes for the site(s) referenced in Question 2?

   ☐ Yes ☐ No

9. How does your organization conduct its change management activities for BES Cyber Assets?

   ____
   ____
   ____
   ____
   ____
   ____
   ____

10. Does your company have supply chain or other internal control protocols in place for the purchase and maintenance of computer systems that are housed at the site(s) referenced in Question 2?

    ☐ Yes ☐ No

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For the purpose of responding to the remainder of this questionnaire, a Transmission Line is defined by the protection system(s) that would be used to isolate a fault on a line. Typically, all sources of fault current for a line fault will be interrupted by breakers. Transmission Lines can be single-ended, two-ended, or three-ended. After identifying your Transmission Lines, the NERC definition of BES should be applied to each line to determine if it is a BES Transmission Line. Single-ended, or radial lines, are not typically considered to be BES assets.

Only include Transmission Lines where you have the ability to remotely operate a device to interrupt network flow (through-flow across the line). If you have remote control of multiple devices on a single Transmission Line as defined above, you should only count that line one time in your response. You should still count the line even if another entity controls the remote end of the line.

11. Provide the following information:

	Total number of BES Transmission Lines where you have the ability to remotely operate a device to interrupt network flow on the line.	Total number of BES Transmission Lines where you have the ability to remotely operate a device to interrupt network flow on the line AND another entity has the ability to remotely operate a device to interrupt flow on the same element or a series element.
100 kV to 199 kV		
200 kV to 299 kV		
300 kV to 499 kV		
500 kV and above		

Attachment 2: Field Test Questionnaire Two

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CIP-002 Transmission Owner Control Centers (TOCCs) Field Test Questionnaire 2

Project 2021-03

Please complete the following questions to help us better understand your system.

As a NERC Control Center is applicable to specific configurations, an entity may have no CC, may have one, or could possibly have multiple CC locations. To the extent that an entity has multiple CC locations that control different BES Transmission Elements, the entity should complete a separate questionnaire for each CC location or clearly delineate between each CC location on the questionnaire as the individual outcomes of the application of Criterion 2.12 could be different.

Terms explained for the purposes of this questionnaire. (Definitions below apply to this questionnaire and are not necessarily consistent with other ERO approaches.)

- Capability – An entity has the capability to operate if that registered entity's "*control environment*" (Control Center, control room, site where personnel are physically are located to perform duties to conduct the delivery of electricity) has one or more SCADA/PLC/Other electronic control system(s) that can operate electrical equipment such as breakers, switches, or disconnects in either normal or emergency conditions. The entity may have the authority to operate electrical equipment or may require authorization from another entity prior to operating electrical equipment.
- Authority – An entity with the authority to operate electrical equipment has the contractual ability to either operate electrical equipment, or give orders to another entity with the capability (but no authority) to operate electrical equipment.
- Operate – The ability to enable the function of an electrical device or equipment. Examples include opening a breaker or disabling the reclosing function of a breaker. Operations may be performed locally (e.g., at a substation) or remotely (e.g., from a different substation or from a Control Center/control room/site where personnel are physically located to perform tasks as required for the delivery of electricity).

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Reference Question 2 from Questionnaire 1:

Do you have a site that is staffed by operating personnel, from which you can remotely operate BES Transmission Elements at two or more locations?

☐ Yes ☐ No

Complete the following for the site(s) referenced in Question 2:

1. How many Bulk Electric System (BES) breakers do you have the capability[1] to operate from this site via SCADA, including any breakers that you would only operate with authority[2] from another entity?

   ____

2. How many BES switches do you have the capability to operate from this site via SCADA, including any switches that you would only operate with authority from another entity?

   ____

3. Aside from your capability to operate devices from this site via SCADA, do you require authorization from another entity prior to operating any device? Do you have the capability to operate any devices via SCADA in an emergency independent of your authorizing entity? Please describe your capability and authority with respect to operation of your electrical devices.

   ____

   ____

   ____

   ____

[1] Reference definition on Page 1 of this document.
[2] Reference definition on Page 1 of this document.

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4.

a. Have you adapted your SCADA system at this site to enable/disable the capability to operate any of your BES Transmission Elements?

☐ Yes ☐ No

b. If so, did your enabling/disabling occur via a physical disconnection (visible open/air gap) or via software? What actions would be required to restore SCADA capability?

____

____

5. Does another entity have the capability to fully isolate your BES Transmission Elements from the BES via their own SCADA systems that do not rely on cyber systems located at this site?

☐ Yes ☐ No

6. Have your BES Transmission Elements ever intentionally or unintentionally been cut off from the BES? If yes, describe any resulting impacts to the remaining BES.

☐ Yes ☐ No

____

____

____

____

7.

a. Does any other entity have the capability to operate your BES Transmission Elements[3] via their own SCADA system?

☐ Yes ☐ No

b. If yes, must that entity rely on any cyber asset associated at this site such as, but not limited to, ICCP?

☐ Yes ☐ No

[3] This excludes equipment owned by you where you are not able to control, access, nor perform maintenance activity. Such equipment is located within another entity's Facility, and ownership is solely designated to hold you responsible for the cost of maintenance as required and performed by the other entity.

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8. Are you required to provide data from your BES Cyber Systems (BCS) to Transmission Operators (TOP) or Reliability Coordinators (RC) per IRO-010 and TOP-003, as necessary for those entities to perform their Operational Planning Analysis, Real-time monitoring, and Real-time Assessments? If so, describe the impact to those entities if your data link to that entity were to go down. Explain any mitigating actions that you would take until your data link could be restored. Please provide the date and time, along with a description of impacts to any TOP/RC, for any past event in which your data link to that entity went down in the past five years.

   ☐ Yes ☐ No

   ____

   ____

   ____

   ____

   ____

9. Can protective relays and/or metering equipment be remotely accessed by a BES Cyber System located at your site? What level of access (i.e., event and fault data only and/or ability to change relay settings and metering configuration)?

   ☐ Yes ☐ No

   ____

10. Do you have a contingency plan for loss/interruption of BES Cyber System(s) located at your site? At a high level, what does it cover?

   ☐ Yes ☐ No

   ____

   ____

   ____

   ____

   ____

11. Please complete the TOCC Definition Power Flow Instruction Document associated with Questionnaire 2 for each site.

Attachment 3: Field Test Questionnaire Two – Power Flow

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Project 2021-03 TOCC Field Test

Questionnaire 2 Power Flow Instruction Document

February 2022

Purpose

The purpose of this document is to provide instructions for entities participating in the Project 2021-03 Standard Drafting Team field test. The goal of the power flow study types in this field test is to evaluate system responses to specific conditions by means of Steady-State power flow runs. These conditions are provided for each study type, beginning on the next page.

Please complete each field requested in this document as it pertains to the study(ies) performed. All requested data should be entered into the tables provided.

Software Used

Detail the name and version of the software used to conduct the power flow study(ies).
Example: PSS/E Version 34.7

Name	
Version #	

Model(s) Used

Models used should include all BPS system elements for your entity's system as well as all BPS system elements of each neighboring system. As a goal of this study is to evaluate potential impacts in the current topology of the system, models are expected to be within the current or near-term timeframe. Consider near-term as 1-3 year models or 1-5 year models, as available. Add rows if more than 1 model is used.
Example: Eastern Interconnection 2020 MMWG series model, year 3

Description of models(s) used	

Case(s) Used

Cases considered for study should include various stressed system conditions. Intentional intrusions into cyber assets causing larger system impacts may align with stressed system conditions to expand the adverse effects on the BPS. Provide a brief description of the case(s) selected for study along with a brief justification on the appropriateness for the case(s) studied. Add rows for additional cases/scenarios studied.
Example: Year 1 and year 2 Summer Peak Load case;
Example: Year 1 and year 2 shoulder (fall season), light load, high wind scenario
Example: Year 1 extreme weather condition

Case Description and justification for use	
Case Description and justification for use	
Case Description and justification for use	

Criteria Used

Criteria used for this field test should be consistent with criteria used by entity's Transmission Planner or Reliability Coordinator for assessing instability, Cascading, and uncontrolled separation. Provide technical justification if other criteria are used. If certain criteria below are not used, please indicate the criteria is not used instead.

Formatting Instructions

Do not delete text or change formatting of tables. Additional rows should be added to each table as needed to accommodate your results. Unused rows may be left empty or can be deleted.

Additional Notes

Each study type will include a field for additional notes. Please use this field to consolidate any additional pertinent material on selection justifications, explanations for items/choices that are not collected in provided tables. These additional notes may also be used to provide clarity on entity-specific system conditions, nuance, or other issues.

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Power Flow Study Type 1

Goal: Evaluate system response for violations of thermal and voltage rating criteria in Steady-State.
Area to be evaluated: Entity's own system as well as all neighboring systems.
Study conditions: All breakers/switches that can be operated remotely from the entity's BES Cyber System are simultaneously opened.
Guidance for conducting in power flow program:

1) Create 1 or more sub-areas that comprise all affected buses per study conditions.
2) Lock generator response, tap changes, and shunts.
3) Set monitors on newly created tie-lines from sub-area(s) and neighboring buses.
4) Open newly created tie-lines, solve case.

Criteria Evaluated

Voltage: Provide voltage magnitude threshold as well as voltage deviation threshold.
Example: Voltage Magnitude threshold = 0.95 p.u., Voltage Deviation threshold = 5% change from initial voltage; Rationale based on TP's criteria used in TPL studies

Voltage Criteria	Description	Rationale / Technical Justification
A		
B		

Thermal: Provide ratings used for evaluating thermal overloads. Include % and time. Include additional details of rating such as "ambient-adjusted" specifications if used. Additional rows provided if evaluating multiple ratings.
Example: Rating A = 100% of continuous summer rating, Rating B = 100% of 15 minute emergency rating

Thermal Rating	Description	Rationale / Technical Justification
A		
B		

Total Load Loss: Provide total load loss criteria (if used) for evaluating Cascading or instability.
Example: 500MW total loss of load

Total load loss criteria (MW)	

Total Generation Loss: Provide total generation loss criteria (if used) for evaluating Cascading or instability.
Example: 700MVA total loss of generation

Total generation loss criteria (MVA)	

Transfer Analysis: Describe the method of any transfer analysis conducted.

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Q-V Analysis: Describe the method of any Q-V analysis conducted.

Results

Did the case solve after applying the study conditions?

Yes/No?	

What calculation method was used to solve the case?

Power flow calculation method used	

How many iterations did the solution take to solve?

Number of iterations	

Identify any voltage criteria violations on monitored buses. Maintain a record of model bus names and numbers, but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed.

Violation #	Initial Voltage p.u.	Final Voltage p.u.	Delta change % (Final-Initial)/Initial *100
V1			
V2			
V3			
V4			
V5			

Identify any thermal criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed.

Violation #	Rating Violated	Initial Rating MVA	Final Rating MVA	% Above Rating Threshold
T1				
T2				
T3				
T4				
T5				

Total Load Loss (MW)

Total Generation Loss (MVA)

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Transfer Analysis Results: Describe notable impact (adverse or beneficial) on neighboring transfer paths/flowgate capabilities. Adjust the table as needed for your results.

Q-V Analysis: Provide the results of any voltage instability identified. Maintain a record of generator/bus used for this analysis but do not provide in this record. In your own records, retain a mapping to the generator/bus #s prepopulated in this record for future reference. Add additional rows and generator/bus #s as needed.

Generator/Bus	Voltage (p.u.)	Actual MVARs
01		
02		

Additional Notes: Provide any additional information that you find as pertinent information to include with your results that do not fit in a table above.

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Power Flow Study Type 2

Goal: Evaluate system response for violations of thermal and voltage rating criteria in Steady-State.
Area to be evaluated: Entity's own system as well as all neighboring systems.
Study conditions: All lines and autotransformers which an entity is capable of interrupting through-flow from the entity's BES Cyber System are operated sequentially.
Guidance for conducting in power flow program:

1) Identify all affected lines and autotransformers per the study conditions.
2) Operate each line/auto, beginning with the most heavily loaded line/auto to the least loaded in sequential order. Solve cases between each operation.
3) Allow generator responses, tap changes, and shunts to switch between each sequential operation and Steady-State case solution (i.e. allow system enough time stabilize).
4) Monitor all affected neighboring buses.
5) Open additional lines if criteria thresholds are violated. Note to use appropriate thermal ratings based on loading time for this study (such as a 15 minute emergency rating versus a 2-hour emergency rating)
6) Evaluate total/aggregate number of thresholds violated, total load loss, and total generation loss against Cascading criteria.
7) Continue through all operations.

Criteria Evaluated

Voltage: Provide voltage magnitude threshold as well as voltage deviation threshold.
Example: Voltage Magnitude threshold = 0.95 p.u., Voltage Deviation threshold = 5% change from initial voltage; Rationale based on TP's criteria used in TPL studies

Voltage Criteria	Description	Rationale / Technical Justification
A		
B		

Thermal: Provide ratings used for evaluating thermal overloads. Include % and time. Include additional details of rating such as "ambient-adjusted" specifications if used. Additional rows provided if evaluating multiple ratings.
Example: Rating A = 100% of continuous summer rating, Rating B = 100% of 15 minute emergency rating

Thermal Rating	Description	Rationale / Technical Justification
A		
B		

Total Load Loss: Provide total load loss criteria (if used) for evaluating Cascading or instability.
Example: 500MW total loss of load

Total load loss criteria (MW)	

Total Generation Loss: Provide total generation loss criteria (if used) for evaluating Cascading or instability.
Example: 700MVA total loss of generation

Total generation loss criteria (MVA)	

Cascading: Following an operation per the instructions, provide the conditions for declaring Cascading conditions.
Example: Total number of sequential line/bus operations that occur following an event. Operations may be due to subsequent voltage or thermal violations.

Description of Cascading Criteria	

Transfer Analysis: Describe the method of any transfer analysis conducted.

Q-V Analysis: Describe the method of any Q-V analysis conducted.

Results

Did the case solve for all operations identified in the study conditions?

Yes/No?	

If "No," include additional details per this table:

Number of operations successfully performed before the case failed to solve:	
Number of potential operations remaining:	

What calculation method was used to solve the case?

Power flow calculation method used	

At any point, what was the highest number of iterations the solution took to solve?

Max number of iterations	

Identify any voltage criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed.

Violation #	Initial Voltage p.u.	Final Voltage p.u.	Delta change % (Final-Initial)/Initial *100
V1			
V2			
V3			
V4			

V5			

Identify any thermal criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed.

Violation #	Rating Description	Initial Rating MVA	Final Rating MVA	% Above Rating Threshold
T1				
T2				
T3				
T4				
T5				

Total Load Loss (MW)

Total Generation Loss (MVA)

Cascading: Provide the results of any Cascading condition that occurred.
Example: 5 additional lines opened following the operation of line 7. All 5 sequential trips were due to violation exceedances of thermal rating B. Additional overloads were not investigated following the declaration of a Cascading condition.

Transfer Analysis Results: Describe notable impact (adverse or beneficial) on neighboring transfer paths/flowgate capabilities. Adjust the table as needed for your results.

Q-V Analysis: Provide the results of any voltage instability identified. Maintain a record of generator/bus used for this analysis but do not provide in this record. In your own records, retain a mapping to the generator/bus #s prepopulated in this record for future reference. Add additional rows and generator/bus #s as needed.

Generator/Bus	Voltage (p.u.)	Actual MVARs
01		
02		

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Additional Notes: Provide any additional information that you find as pertinent information to include with your results that do not fit in a table above.

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Power Flow Study Type 3

Goal: Evaluate system response for violations of thermal and voltage rating criteria in Steady-State.
Area to be evaluated: Entity's own system as well as all neighboring systems.
Study conditions: Study a broad range of system conditions following a wider range of probable Contingencies.
Guidance for conducting in power flow program:

1) Refer to the TPL-001-4 Planning Assessment results for affected system elements in the area to be evaluated.
2) Consider evaluating all extreme events such as those identified for Steady State in Table 1 of TPL-001-4.

Criteria Evaluated

Voltage: Provide voltage magnitude threshold as well as voltage deviation threshold.
Example: Voltage Magnitude threshold = 0.95 p.u., Voltage Deviation threshold = 5% change from initial voltage; Rationale based on TP's criteria used in TPL studies

Voltage Criteria	Description	Rationale / Technical Justification
A		
B		

Thermal: Provide ratings used for evaluating thermal overloads. Include % and time. Include additional details of rating such as "ambient-adjusted" specifications if used. Additional rows provided if evaluating multiple ratings.
Example: Rating A = 100% of continuous summer rating, Rating B = 100% of 15 minute emergency rating

Thermal Rating	Description	Rationale / Technical Justification
A		
B		

Total Load Loss: Provide total load loss criteria (if used) for evaluating Cascading or instability.
Example: 500MW total loss of load

Total load loss criteria (MW)	

Total Generation Loss: Provide total generation loss criteria (if used) for evaluating Cascading or instability.
Example: 700MVA total loss of generation

Total generation loss criteria (MVA)	

Contingencies Evaluated: Provide a description for each Contingency or set of Contingencies run.
Example: Contingency C01 = loss of generator followed by loss of line, all applicable assets

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Contingency #	Description
C01	
C02	
C03	
C04	
C05	
C06	
C07	
C08	
C09	
C10	

Results

Did the case solve for all operations identified in the study conditions?

Yes/No?	

If "No," include additional details per this table:

Number of operations successfully performed before the case failed to solve:	
Number of potential operations remaining:	

What calculation method was used to solve the case?

Power flow calculation method used	

At any point, what was the highest number of iterations the solution took to solve?

Max number of iterations	

Identify any voltage criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed. Also include a brief description of the Contingency that caused the violation. Do not use bus/line names in the description; only describe in generic terms what operated.
Example of Contingency Description: Loss of tower line 42; tower had three 230kV circuits

Violation #	Initial Voltage p.u.	Final Voltage p.u.	Delta change % (Final-Initial)/Initial *100	Description of Contingency
V1				
V2				
V3				
V4				
V5				

Identify any thermal criteria violations on monitored buses. Maintain a record of model bus names and numbers but do not provide in this record. In your own records, retain a mapping to the violation #s prepopulated in this record for future reference. Add additional rows and violation #s as needed. Also include a brief description of the Contingency that caused the violation. Do not use bus/line names in the description; only describe in generic terms what operated.

Violation #	Rating Description	Initial Rating MVA	Final Rating MVA	% Above Rating threshold	Description of Contingency
T1					
T2					
T3					
T4					
T5					

Additional Notes: Provide any additional information that you find as pertinent information to include with your results that do not fit in a table above.

Attachment 4: Field Test Questionnaire Three

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CIP-002 Transmission Owner Control Centers (TOCCs) Field Test Questionnaire 3

Project 2021-03

Please complete the following questions to help us better understand your system.

As a NERC Control Center is applicable to specific configurations, an entity may have no CC, may have one, or could possibly have multiple CC locations. To the extent that an entity has multiple CC locations that control different BES Transmission Elements, the entity should complete a separate questionnaire for each CC location or clearly delineate between each CC location on the questionnaire as the individual outcomes of the application of Criterion 2.12 could be different.

1. Do the BES Cyber Systems associated with your Control Center meet any of the following CIP-002-5.1a criteria for High Impact? Please provide any clarifying comments below.

   ☐ Criteria 2.2 ☐ Criteria 2.4 ☐ Criteria 2.5 ☐ Criteria 2.7
   ☐ Criteria 2.8 ☐ Criteria 2.9 ☐ Criteria 2.10 ☐ None

   ____

   ____

   ____

2. Please populate the table below and provide an "aggregate weighted value" by summing the "weighted value per line" shown in the table below for each BES Transmission Line monitored and controlled by the Control Center.

   Please submit a revised one-line that identifies each line that was included in your analysis.

Voltage Value of a Line	Weight Value per Line	Number of Lines	Aggregate Value
Less than 100kV	0		0
100 kV to 199 kV	250		
200 kV to 299 kV	700		
300 kV to 499 kV	1300		
500 kV and above	0		

Total Aggregate Weighted Value: ____

(Enter "Medium Risk" if number of 500 kV lines is greater than zero)

3. Are any of your BES Transmission Elements included as a part of an interface that has been defined as a permanent Flowgates in the Eastern Interconnection, a major transfer path within the Western Interconnection, or comparable interface in the ERCOT Interconnection (e.g., Generic Transmission Constraint) or the Quebec Interconnection? Please explain in the comment box below should you check unknown, or if you have any further clarifying comments.

☐ Yes ☐ No ☐ Unknown

4. Are any of your BES Transmission Elements included as part of a contingency for any permanent Flowgates in the Eastern Interconnection, major transfer paths within the Western Interconnection, or comparable monitored facility in the ERCOT Interconnection (e.g., Generic Transmission Constratin) or the Quebec Interconnection? Please explain in the comment box below should you check unknown, or if you have any further clarifying comments.

☐ Yes ☐ No ☐ Unknown

5. Were any of your BES Transmission Elements included as part of a prior outage for any permanent Flowgates in the Eastern Interconnection, major transfer paths within the Western Interconnection, or comparable monitored facility in the ERCOT Interconnection (e.g., Generic Transmission Constratin) or the Quebec Interconnection? Please explain in the comment box below should you check unknown, or if you have any further clarifying comments.

☐ Yes ☐ No ☐ Unknown

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6. Have any of your BES Transmission Elements been identified by your Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies? Please explain in the comment box below should you check unknown, or if you have any further clarifying comments.

   ☐ Yes ☐ No ☐ Unknown

   ____

   ____

   ____

7. Do you have any automatic Load shedding that is performed by a common control system that implements Load shed without human operator initiation? A common control system would exclude underfrequency load shedding (UFLS) and undervoltage load shedding (UVLS) that is implemented by individual relays located at discrete stations or substations. If you answer yes, please describe the purpose of the scheme and total peak load impacted.

   ☐ Yes ☐ No ☐ Unknown

   ____

   ____

   ____

8. Are any of your BES Transmission Elements included as a monitored element for any Remedial Action Schemes (RAS)? If you answer yes, please describe the purpose of the RAS and the impact to the BES if the RAS fails to operate as designed.

   ☐ Yes ☐ No ☐ Unknown

   ____

   ____

   ____

9. Are any of your BES Transmission Elements operated (i.e., opened or closed) via any Remedial Action Schemes (RAS) or Special Protection Systems (SPS)? If you answer yes, please describe the purpose of the RAS and the impact to the BES if the RAS fails to operate as designed.

   ☐ Yes ☐ No ☐ Unknown

   ____

   ____

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10. Do you have any BES Transmission Elements providing the generation interconnection required to connect BES generator resource output equal to or greater than an aggregate of 1500 MW that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation resource to your interconnected neighbors (TOP/TSP/BA)?

☐ Yes ☐ No ☐ Unknown

11. Do you have any BES Transmission Elements that are critical to system restoration associated with Blackstart Resources?

☐ Yes ☐ No ☐ Unknown

12. Do you have any BES Transmission Elements that are included in the Cranking Paths and initial switching requirements of any Transmission Operator's restoration plan?

☐ Yes ☐ No ☐ Unknown

13. Can another entity de-energize your system from the BES via operation of their devices or remote control of your devices? What is the minimum number of breakers/switches that another single entity can remotely control in order to de-energize your system. If two or more entities must work cooperatively to de-energize your system while keeping other systems whole, then provide the minimum number of entities and breakers/switches needed to isolate your system. Please identify these breakers/switches on a revised one-line submittal.

____

____

____

____

____

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:	CIP-002 Communications Protocol Converters SAR		
Date Submitted:	February 3, 2023		
SAR Requester			
Name:	Dr. Trey Melcher CISSP, CISM, CRISC		
Organization:	Burns & McDonnell		
Telephone:	314-391-9648	Email:	tmelcher@burnsmcd.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?):			
Section 4.2.3 of CIP-002-5.1a exempts "Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters." There are situations where Cyber Assets inside of a Control Center's Electronic Security Perimeter require communication to serially connected transmission facilities by using protocol converters. If the transmission facility does not have a defined Electronic Security Perimeter, the exemption of Section 4.2.3 is not applicable as two discrete Electronic Security Perimeters do not exist. There are inconsistencies in interpretations and approaches in categorizing such protocol converters when the Transmission Owner considers the transmission facilities to not have External Routable Connectivity or an Electronic Security Perimeter. This is found in transmission facilities with medium impact Bulk Electric System (BES) Cyber Systems having only serial communications traversing the physical location or transmission facilities with low impact BES Cyber Systems having no applicability for an Electronic Security Perimeter as required by CIP-005 (medium and high impact only).			

Requested information
Additionally, when the protocol converters are physically located within the Transmission Operator's Control Center, or associated datacenter, and not at the Transmission Owners transmission facility, the Transmission Operator owns and manages the protocol converters as opposed to the Transmission Owner. Other situations may exist where protocol converters are part of a Wide Area Network not owned or managed by either Registered Entity. In such situations, there is not an associated Functional Entity type defined in Appendix 5B of the Rules of Procedure. This Standard Authorization Request is to consider if such a protocol converter meets the definition of a BES Cyber Asset by having an adverse impact to one or more facilities and the reliable operation on the BES. This includes consideration to the threat of unavailability, degradation, or misuse to a connected BES Cyber System and the aggregation of serial system-to-system communications from substations to Control Center BES Cyber Systems. As such, this project supports reliability by clarifying how these protocol converters should be categorized and if they are to reside within a defined Electronic Security Perimeter.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This project would provide clarification through revisions to CIP-002 on when a communication protocol converter meets the definition of a BES Cyber Asset
Project Scope (Define the parameters of the proposed project):
This project will make revisions to CIP-002 to clarify if communication protocol converters between a Control Center and a transmission facility meet the definition of a BES Cyber Asset and have a 15-minute impact. Consideration should also be given to generation Control Centers and facilities as protocol converters may also be used in the communication paths.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Revise CIP-002 to include the identification of communication protocol converters and the relationship to the exception in Section 4.2.3. Specifically, the revisions would be to CIP-002-5.1a Requirement R1, and relevant attachments as necessary, regarding clarification for system-to-system serial communication protocol converters between a Transmission Owner low or medium impact BES Cyber System that connects to a Transmission Operators BES Cyber Systems by either enforcing an authentication break or by residing inside a defined Electronic Security Perimeter.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
Consideration should also be giving the security and reliability impacts. Moving the protocol converters inside of an existing Electronic Security Protocol may lower the security posture as the serial traffic is not required to transverse through an Electronic Access Point. Additionally, protocol converters range from capabilities and could lead to technical challenges and limitations when attempting to add authentication breaks on such system-to-system communication links. Consideration should also be given to other types of Cyber Assets used in the communication paths, such as routers and switches, along with ownership and management of the Cyber Assets as applicable to Functional Entity types defined in Appendix 5B of the Rules of Procedure.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact is unknown at this time.
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 physical location of protocol converters is generally inside the Control Center and Physical Security Perimeter, but logically located outside of an Electronic Security Perimeter. This creates a scenario whereby categorizing the protocol converters as a BES Cyber Asset and moving them into an Electronic Security Perimeter bypasses the Electronic Access Point.
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):
Transmission Operator and Transmission Owner. There is a potential that Generator Operator Control Centers and Generator Owner facilities could have similar architectures and Cyber Assets. The modifications to the Standard should include both transmission and generation architectures.
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None
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)?
NERC Project 2021-03 CIP-002
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.

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

Requested information
None

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

Market Interface Principles	
Does the proposed standard development project comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
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	None

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

Unofficial Comment Form

Project 2021-03 CIP-002 Transmission Owner Control Centers

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on the **CIP-002 Communications Protocol Converters standard authorization request (SAR)** by **8 p.m. Eastern, Friday, March 31, 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

On January 19, 2022, the Standards Committee (SC) accepted the Burns & McDonnell request for information (RFI). During its February 16, 2022 meeting, the SC assigned the RFI to NERC Project 2021-03 – CIP-002 Transmission Owner Control Center and authorized solicitation for supplemental standard drafting team (SDT) members. From May 23 through June 22, 2022, NERC solicited supplemental nominations for volunteers to serve on the NERC Project 2021-03 CIP-002 SDT. The supplemental SDT members were appointed at the September 21, 2022 SC meeting.

After review of the RFI, the CIP-002 SDT determined that the issue raised could be consider as part of the 2021-03 SDT's work given the team is already modifying CIP-002. NERC staff worked with Burns & McDonnell, the original RFI submitters, to draft a SAR. The SC rejected the RFI, accepted the SAR, and assigned the SAR to project 2021-03 CIP-002 SDT during its February 22, 2023.

Modifications to CIP-002 SAR – Accepted by the Standards Committee on February 22, 2023

There are inconsistencies in interpretations and approaches in categorizing such protocol converters when the Transmission Owner considers the transmission facilities to not have External Routable Connectivity or an Electronic Security Perimeter. This is found in transmission facilities with medium impact Bulk Electric System (BES) Cyber Systems having only serial communications traversing the physical location or transmission facilities with low impact BES Cyber Systems having no applicability for an Electronic Security Perimeter as required by CIP-005 (medium and high impact only).

Questions

1. Do you agree with the proposed scope as described in the CIP-002 Communications Protocol Converters SAR? 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 drafting team to consider, if desired.

   Comments:

Standards Announcement

Project 2021-03 CIP-002
Standard Authorization Request

Formal Comment Period Open through March 31, 2023

Now Available

A 30-day formal comment period for the **CIP-002 Communications Protocol Converters Standard Authorization Request**, is open through **8 p.m. Eastern, Friday, March 31, 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 more information on the Standards Development Process, refer to the Standard Processes Manual.

For more information or assistance, contact Senior 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 2021-03 CIP-002 Transmission Owner Control Centers Observer List" in the Description Box.

Comment Report

Project Name:	2021-03 CIP-002 | Communications Protocol Converters SAR
Comment Period Start Date:	3/2/2023
Comment Period End Date:	3/31/2023
Associated Ballots:	

There were 31 sets of responses, including comments from approximately 97 different people from approximately 78 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 CIP-002 Communications Protocol Converters SAR? 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 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
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO

					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
California ISO	Monika Montez	2	WECC	ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002	Monika Montez	CAISO	2	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kathleen Goodman	ISO-NE	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Elizabeth Davis	PJM	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Andrew Gallo	Electric Reliability Council of	2	Texas RE

						Texas, Inc.		
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Sheraz Majid	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
					Chantal Mazza	Hydro Quebec	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Dan Kopin	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
					Nicolas Turcotte	Hydro-Qu?bec TransEnergie	1	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	6	NPCC

						Department of Public Service		
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC

1. Do you agree with the proposed scope as described in the CIP-002 Communications Protocol Converters SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

The MRO NSRF agrees with the direction to add additional clarity for communication protocol converters.

The MRO NSRF suggests the scope of the SAR should also include a review of the exclusion:

Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters

The wording of the exclusion is what has created ambiguity. The SDT may not modify CIP-002 but instead update the exclusion. One of the intents of the exclusion is to enable RE to use third party telecommunication companies, and exclude equipment used by these companies as they are not a RE. The type of equipment in use by a telecommunication company in order to provide a service is not always known.

The SAR should take in to account if multiple protocol converters are used. For example, a protocol converter may be used to convert an incoming serial connection to an IP-based protocol. However earlier on in the transmission, the incoming serial connection may have been converter to an IP-based protocol, then converted back to a serial protocol.

Related projects must also include “Project 2016-02 Modifications to CIP Standards” as the SDT is working on a revision to the same exclusion to support the use of “super ESP” where and ESP spans multiple PSP.

The type of protocol conversion should also be considered by the SAR. Some protocol converters exist that translate a serial protocol in to another serial protocol. Others will convert a serial protocol to an IP based protocol. These represent two different categories of devices based on their connectivity.

Likes 0	
Dislikes 0	
Response	
Alan Kloster - Evergy - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates the comments of the Edison Electric Institute (EEI) for question #1.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
MidAmerican strongly supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

Manitoba Hydro suggests the scope of the SAR should also include a review of the exclusion:

Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters

The wording of the exclusion is what has created ambiguity. The SDT may not modify CIP-002 but instead update the exclusion. The scope of the SAR should therefore include all of the NERC CIP standards as this exclusion text is included in all standards CIP-002 to CIP-013. One of the intents of the exclusion is to enable RE to use third party telecommunication companies, and exclude equipment used by these companies as they are not a RE. The type of equipment in use by a telecommunication company in order to provide a service is not always known.

The SAR should take in to account if multiple protocol converters are used. For example, a protocol converter may be used to convert an incoming serial connection to an IP-based protocol. However earlier on in the transmission, the incoming serial connection may have been converter to an IP-based protocol, then converted back to a serial protocol.

Related projects must also include “Project 2016-02 Modifications to CIP Standards” as the SDT is working on a revision to the same exclusion to support the use of “super ESP” where and ESP spans multiple PSP.

The type of protocol conversion should also be considered by the SAR. Some protocol converters exist that translate a serial protocol in to another serial protocol. Others will convert a serial protocol to an IP based protocol. These represent two different categories of devices based on their connectivity.

Likes 0	
Dislikes 0	
Response	

Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	
Answer	No
Document Name	
Comment	

NST agrees that as currently written, CIP-002 exception 4.2.3.2 ("Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters") does not address situations where BES Cyber Systems within an ESP communicate with remote BES Cyber Systems that are Low Impact or have only serial communication interfaces and, consequently, no ESP. However, NST strongly disagrees with the notion that the best, in fact only, way to address this gap is by making significant and highly prescriptive changes to CIP-002.

The statement, "…this project supports reliability by clarifying how these protocol converters should be categorized and if they are to reside within a defined Electronic Security Perimeter" is problematic in two respects. First, CIP-002 already requires Responsible Entities to evaluate whether Cyber Assets either "used by and located at" or "associated with" BES assets (Control Center, generation or transmission facility, etc.) meet the definition of a BES Cyber System. If protocol converters are, for example, "used by and located" at a TOP Control Center, the TOP is already obligated to determine whether (a) they are Cyber Assets (per the NERC Glossary definition) and, if so, (b) they are BES Cyber Assets. Second, the obligation to locate High or Medium Impact BES Cyber Systems that meet certain criteria within an Electronic Security Perimeter is the province of CIP-005, not CIP-002. A protocol converter that is identified as a High or Medium Impact BCS and connects to a network using a routable protocol is already addressed by CIP-005. No additional requirement language is needed.

NST is unclear about the intended purpose of the paragraph that reads, "Additionally, when the protocol converters are physically located within the Transmission Operator's Control Center, or associated datacenter, and not at the Transmission Owners transmission facility, the Transmission Operator owns and manages the protocol converters as opposed to the Transmission Owner. Other situations may exist where protocol converters are part of a Wide Area Network not owned or managed by either Registered Entity. In such situations, there is not an associated Functional Entity type defined in Appendix 5B of the Rules of Procedure." Do the SAR authors believe these possible circumstances represent problems that need to be addressed? If so, the SAR does not appear to offer any proposed solutions.

The SAR is, in NST's opinion, self-contradictory. It suggests that protocol converters should perhaps be classified as BES Cyber Systems and located with ESPs. A few short sentences later, it expresses concern about the possible security implications of using serial communications lines to connect external devices to BES Cyber Systems and/or PCAs within ESPs, thereby bypassing ESP Electronic Access Points.

The SAR mentions "authentication breaks" as a potential new requirement for serial communication links between BES Cyber Systems at different facilities. Do the SAR authors believe there should be requirements for remote serial communications similar to those for CIP-005 Interactive Remote Access, namely, the serial equivalent of Intermediate Systems? If so, the "Industry Need" section needs to be rewritten (it says nothing about authentication) and the Standard to be revised should be CIP-005, not CIP-002.

NST is particularly concerned about the statement, "Consideration should also be given to other types of Cyber Assets used in the communication paths, such as routers and switches, along with ownership and management of the Cyber Assets as applicable to Functional Entity types defined in Appendix 5B of the Rules of Procedure." What communication paths, and whose Cyber Assets? Some communication links between BES Cyber Systems and "outside" (of either an ESP or a BES facility) traverse and use Responsible Entity corporate network infrastructures, which of course include switches and routers. This has the security benefit of allowing ESP Electronic Access Points to be situated within their respective corporate networks, as opposed to being directly connected to the public Internet. Forcing Entities to classify all Entity-owned routers and switches in such communication links as BES Cyber Systems because the links don't qualify for the exception in Section 4.2.3.2 could have the unintended consequence of leading to Internet-facing CIP-005 Electronic Access Points, or, worse, an expectation that Responsible Entities should be obligated by the CIP Standards to protect everything, everywhere, all at once.

NST suggests that instead of proposing disruptive and, in our opinion, unnecessary changes to CIP-002 requirements, the problem with the language in

Section 4.2.3.2 (which, we note, seems to have been dealt with reasonably well by industry for the six years and nearly nine months that have elapsed since CIP Version 5 became effective) would be better addressed by revising that section instead of the entire Standard. Language similar to the “outside the asset” qualifier in CIP-003-8 Attachment 1 Section 3.1 could be used to address networks and data communication links to and from BES assets containing Low Impact BES Cyber Systems or Medium Impact BES Cyber Systems that have no ESP.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5,6

Answer	No
Document Name	

Comment

Constellation aligns comments in agreement with Exelon.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Justin Kuehne - AEP - 3,5,6

Answer	No
Document Name	

Comment

AEP appreciates the opportunity to provide comments on the SAR for this project. We do not agree with the proposed scope laid out in the SAR and do not believe CIP-002 standard language should be modified due to communications assets already being addressed within the Exemptions Section 4.2.3 of the standard. If modifications to the standard are required, they should be made within the exemptions section rather than within the standard language. Moreover, the concepts laid out in the Detailed Description section of the SAR are more closely tied to CIP-005 rather than the scope of CIP-002, further diminishing the need to modify the standard requirements.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	
Comment	

Texas RE generally supports clarifications to the Reliability Standard language requirements. However, in the present circumstances, Texas RE believes the current Reliability Standard language is clear. Moreover, the question of whether communication protocol converters between a Control Center and a transmission facility meet the definition of a BES Cyber Asset is dependent on design, configuration, and usage. Accordingly, further revision of the A 4.2.3 exemption language may result in additional confusion.

Texas RE recommends considering the following in response to the SAR:

- The determination of whether a Cyber Asset is a BES Cyber Asset does not fall within CIP-002. CIP-002 requires entities to identify BES Cyber Systems or assets that contain BES Cyber Systems. In contrast, the determination of whether a Cyber Asset is a BES Cyber Asset hinges on the definition of BES Cyber Asset. As such, any clarifying revisions regarding the scope of the BES Cyber Asset definition would need to occur in the definition itself. This definition in turn implicates other CIP Standards and those impacts should be considered.
- ·Texas RE is concerned with this statement:

“Additionally, when the protocol converters are physically located within the Transmission Operator’s Control Center, or associated datacenter, and not at the Transmission Owner’s transmission facility, the Transmission Operator owns and manages the protocol converters as opposed to the Transmission Owner. Other situations may exist where protocol converters are part of a Wide Area Network not owned or managed by either Registered Entity. In such situations, there is not an associated Functional Entity type defined in Appendix 5B of the Rules of Procedure.”

Even though a piece of equipment may reside in a certain location does not mean it is owned by that location’s owner. Additionally, this situation is not unique to protocol converters. If it is determined that Wide Area Network (WAN) equipment owned or managed by entities that are not Functional Entities under the NERC Rules of Procedure pose a risk to the reliable operation of the Bulk Electric System then this risk should be addressed in a manner that addresses WAN equipment in general, not a specific subset of WAN equipment.

- In this statement, “There are inconsistencies in interpretations and approaches in categorizing such protocol converters when the Transmission Owner considers the transmission facilities to not have External Routable Connectivity or an Electronic Security Perimeter”, Texas RE notes that the existence of, or lack of, External Routable Connectivity does not impact whether exemption 4.2.3.2 applies. This exemption applies to Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters, both when External Routable Connectivity exists and when it does not.
- Texas RE respectfully disagrees with this statement:

“This is found in transmission facilities with medium impact Bulk Electric System (BES) Cyber Systems having only serial communications traversing the physical location or transmission facilities with low impact BES Cyber Systems having no applicability for an Electronic Security Perimeter as required by CIP-005 (medium and high impact only).”

- CIP-005 contains requirements that must be performed when medium or high impact BCS are located within an ESP, however CIP-005 does not determine if an ESP exists. The definition of ESP does not include BCS impact ratings as a scoping mechanism. If a low impact BCS is connected to a network via a routable protocol then the logical border surrounding that network meets the legal definition of Electronic Security Perimeter.

Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
CIPv5 is predicated on the "System" concept, a BES Cyber System that has a real-time response and applicable BES reliability operating services (BROS) to support the reliable operation of the Bulk Electric System. Protocol converters residing in an ESP are already protected as PCA / BCA. Protocol converters residing outside an ESP are part of the transport Exemption 4.2.3. Serial traffic terminating outside of the ESP must be converted and forwarded through an Electronic Access Point (EAP). BPA feels that the addition of this SAR to Project 2021-03 would result in too many disparate topics under the scope of one project/one SDT.	
Likes 0	
Dislikes 0	
Response	
Carl Pineault - Hydro-Qu?bec Production - 1,5	
Answer	No
Document Name	
Comment	
First, the scope is not clear. The written scope says only CIP-002. The SAR includes topics that are addressed CIP-003 and CIP-005. How big is this scope? Second, the scope requires the reader to interpret. This scope should be explicit. The SAR wants clarification on CIP-002 exemption 4.2.3 but quotes 4.2.3.2. The other items in 4.2.3 do not appear to be in question. As written, this point is too broad. Next, the request's reason appears to be based on CIP-005 R1 and CIP-003. However the reader needs to connect those points. The reason should be more explicit. Third, project 2016-02 (Modifications to CIP Standards) SDT is addressing the underlying question. Project 2016-02 has a V5TAG question on Interactive Remote Access (IRA) which is related to External Routable Connectivity (ERC). That SDT proposed IRA/ERC language earlier that addresses concerns with protocol converters. Fourth, the industry is trying to resolve earlier issues from multiple SDTs simultaneously updating CIP Standards. Project 2021-03's (this CIP-002 SAR) title includes "protocol converter," the underlying question will impact IRA and ERC, so there appears there will likely be significant overlap and possible contradiction in required CIP-002 changes between both the on-going 2016-02 project and the proposed 2021-03 projects, we recommend that 2016-02 completes before 2021-03 project proceeds.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1	

Answer	No
Document Name	
Comment	

First, the scope is not clear. The written scope says only CIP-002. The SAR includes topics that are addressed CIP-003 and CIP-005.

Second, the scope requires the reader to interpret. This scope should be explicit. The SAR wants clarification on CIP-002 exemption 4.2.3 but quotes 4.2.3.2. The other items in 4.2.3 do not appear to be in question. As written, this point is too broad. Next, the request's reason appears to be based on CIP-005 R1 and CIP-003. However the reader needs to connect those points. The reason should be more explicit.

Third, project 2016-02 (Modifications to CIP Standards) SDT is addressing the underlying question. Project 2016-02 has a V5TAG question on Interactive Remote Access (IRA) which is related to External Routable Connectivity (ERC). That SDT proposed IRA/ERC language earlier that addresses concerns with protocol converters.

Fourth, the industry is trying to resolve earlier issues from multiple SDTs simultaneously updating CIP Standards. Project 2021-03's (this CIP-002 SAR) title includes "protocol converter," the underlying question will impact IRA and ERC, so there appears there will likely be significant overlap and possible contradiction in required CIP-002 changes between both the on-going 2016-02 project and the proposed 2021-03 projects, we recommend that 2016-02 completes before 2021-03 project proceeds.

Likes 0	
Dislikes 0	
Response	

Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF

Answer	No
Document Name	
Comment	

Duke Energy supports the intent of the CIP-002 Communications Protocol Converters SAR, but recommends that the scope of the SAR is refined to address the identified need. This would start with a wider examination of the risk that these devices pose in various use cases, which in particular should consider the limited ability for many these devices to be misused or impact reliability upon failure or degradation, and not address simply as a categorization issue. If examination demonstrates an unacceptable reliability risk, the general need would be to revise the standards to provide consistent direction across regions on how entities should assess and protect applicable protocol conversion, specifically system-to-system communications. Limiting the scope of the SAR to CIP-002 precludes the option to edit CIP-005 to consider revisions based on any identified level of risk presented by these devices. Considering a classification change is not the most effective starting point for addressing the identified need.

Likes 0	
Dislikes 0	
Response	

Alain Mukama - Hydro One Networks, Inc. - 1,3

Answer	No

Document Name	
Comment	
We disagree with the SAR because of the below reasons: 1. In the scope, the described scenario (serial between medium to low) is permitted by the existing standards, even though the protocol converters are to be classified BCA. It is unclear if the intent is to add the serial connections into the CIP standards. Such concerns may be discussed in CIP-005/CIP-003 instead of CIP-002; 2. This SAR may overlap with an existing initiative from SDT where the definition of IRA is to be revised in order to address the security concerns over IRA.	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - NA - Not Applicable	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) does not agree with the proposed scope of the SAR and supports the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI does not support this SAR. There may be more appropriate tools to address this concern. We do not support CIP-002 attempting to clarify for all entities how to treat protocol converters in all situations and implementations. CIP-002 should not be changed to define detailed implementation within a CIP system. EEI suggests potentially modifying the CIP-002 technical rationale or the creation of guidance (e.g., white paper, technical paper, or implementation guidance) for aiding entities with this issue.	

Likes 0	
Dislikes 0	
Response	
Justin Welty - NextEra Energy - Florida Power and Light Co. - 1,3,6	
Answer	No
Document Name	
Comment	
NextEra Energy is not in agreement with the SAR request as documented. NERC has multiple SDTs and the impact of CIP-002 extends into other standards. NEE recommends NERC consolidate all CIP-002 SARs and issues into a scope that can address all downstream standards impact.	
Likes 0	
Dislikes 0	
Response	
Brent Sessions - Western Area Power Administration - 3 - MRO,WECC	
Answer	No
Document Name	
Comment	
• The proposed SAR as written is incomplete. There is not cost impact assessment completed, which be required according to the form. • There is an interpretation request also in process (2022-INT-01) which should be answered prior to a SAR being proposed. Without an interpretation, clarification seems unlikely. • In the "Industry Need" section 3rd paragraph, the statement about TOP vs. TO ownership of transmission facilities is over-generalized and only represents one arhictectural and ownership scenario. It is unclear how to put management and/or ownership of specific equipment into a functional registration context. • In the statement on Page 2, "Industry Need" section, 4th paragraph, "…consideration to the threat of unavailability, degradation, or misuse to a connected BES Cyber System and the aggregation of serial system-to-system communications from substations to Control Center BES Cyber Systems." "Aggregation" in this context is vague—how much is too much? CIP-002 R1 already considers control centers as being a higher risk than an individual facility. Additionally, protocol converters do not "aggreate" communication paths—they only convert one protocol to another. Again this SAR assumes very specific BCS and communications architecture.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No

Document Name	
Comment	

FirstEnergy is supportive of EEI comments which state:

EEI does not support this SAR. There may be more appropriate tools to address this concern. We do not support CIP-002 attempting to clarify for all entities how to treat protocol converters in all situations and implementations. CIP-002 should not be changed to define detailed implementation within a CIP system. EEI suggests potentially modifying the CIP-002 technical rationale or the creation of guidance (e.g., white paper, technical paper, or implementation guidance) for aiding entities with this issue.

Likes 0	
Dislikes 0	
Response	

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) would like to thank the SAR Standards Drafting Team for the opportunity to provide feedback on Project 2021-03 – CIP-002 Communications Protocol Convertors. SIGE does not agree with the proposed scope of the SAR and supports the comments as submitted by the Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	
Response	

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

AZPS agrees with EEI’s suggestion to modify the CIP-002 technical rationale or create guidance for aiding entities with this issue. Guidance created to clarify categorization of communications protocol converters should include consideration for non-BES protocol converter nodes which relay converted ```serial communications between Control Centers and transmission facilities.

Likes 0	
Dislikes 0	
Response	

Sean Erickson - Western Area Power Administration - 1,6	
Answer	No
Document Name	
Comment	

· The proposed SAR as written is incomplete.

o There is not cost impact assessment completed, which be required according to the form.

o There is an interpretation request also in process (2022-INT-01) which should be answered prior to a SAR being proposed. Without an interpretation, clarification seems unlikely.

o In the "Industry Need" section 3rd paragraph, the statement about TOP vs. TO ownership of transmission facilities is over-generalized and only represents one arhictectural and ownership scenario. It is unclear how to put management and/or ownership of specific equipment into a functional registration context.

In the statement on Page 2, "Industry Need" section, 4th paragraph, "…consideration to the threat of unavailability, degradation, or misuse to a connected BES Cyber System and the aggregation of serial system-to-system communications from substations to Control Center BES Cyber Systems." "Aggregation" in this context is vague—how much is too much? CIP-002 R1 already considers control centers as being a higher risk than an individual facility. Additionally, protocol converters do not "aggreate" communication paths—they only convert one protocol to another. Again this SAR assumes very specific BCS and communications architecture.

Likes 0	
Dislikes 0	
Response	

Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002	
Answer	No
Document Name	
Comment	

The ISO/RTO Council (IRC) Standards Review Committee (SRC) does not agree with the proposed scope of this SAR for the following reasons:

The proposed scope of this SAR is unclear, as the SAR references topics addressed by CIP-003 and CIP-005, therefore going beyond the stated objective of modifying CIP-002. Additionally, references to exemptions available under 4.2.3 throughout the SAR should be revised to reference subpart 4.2.3.2, since this is the only exemption that appears to be in question.

There is already an existing project 2016-02 (Modifications to CIP Standards) in progress that includes the V5TAG question on Interactive Remote Access (IRA) that is related to External Routable Connectivity (ERC). This project has already proposed IRA/ERC language that addresses concerns with protocol converters. As such, there will be significant overlap and possible contradiction in required CIP-002 changes between project 2016-02 and the proposed addition to project 2021-03. Additionally, exemption 4.2.3.2 exists in other CIP Reliability Standards, such as CIP-005, CIP-007, and CIP-010, and any clarifications regarding the applicability of exemption 4.2.3.2 should also consider the potential impacts on all Standards that contain exemption 4.2.3.2. Project 2016-02 is already addressing modifications to multiple CIP Reliability Standards and is therefore a more appropriate project for this SAR than project 2021-03, which is addressing a narrower subset of CIP Standards.

For these reasons, the SRC believes that the more appropriate path for this SAR is to leverage the Implementation Guidance processes vehicle rather than the SAR process. In order to avoid duplication of effort, the SRC also recommends that project 2016-02 be completed before project 2021-03 addresses the content of this SAR, or that this SAR be processed under project 2016-02 instead of under project 2021-03.

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 Standards Review Committee (SRC).

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We do not agree with this SAR for four reasons.

First, the scope is not clear. The written scope says only CIP-002. The SAR includes topics that are addressed in CIP-003 and CIP-005. How big is this scope?

Second, the scope requires the reader to interpret. This scope should be explicit. The SAR wants clarification on CIP-002 exemption 4.2.3 but quotes 4.2.3.2. The other items in 4.2.3 do not appear to be in question. As written, this point is too broad. Next, the request's reason appears to be based on CIP-005 R1 and CIP-003. However, the reader needs to connect those points. The reason should be more explicit.

Third, project 2016-02 (Modifications to CIP Standards) SDT is addressing the underlying question. Project 2016-02 has a V5TAG question on Interactive Remote Access (IRA) which is related to External Routable Connectivity (ERC). That SDT proposed IRA/ERC language earlier that addresses concerns with protocol converters.

Fourth, the industry is trying to resolve earlier issues from multiple SDTs while simultaneously updating CIP Standards. Project 2021-03's (this CIP-002 SAR) title includes "protocol converter," the underlying question will impact IRA and ERC, so there appears there will likely be significant overlap and possible contradiction in required CIP-002 changes between both the ongoing 2016-02 project and the proposed 2021-03 projects, we recommend that

2016-02 completes before 2021-03 project proceeds.	
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 around this SAR and do not feel it is needed in this form.	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 1,3,6	
Answer	Yes
Document Name	
Comment	
Entergy suggests the scope of the SAR should also include a review of the exclusion: Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation aligns comments in agreement with Exelon Generation. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 1,3	
Answer	
Document Name	
Comment	
PNMR is not in favor of the CIP-002 SAR to address the classification of protocol converters. Although clarification of the CIP-002 exemption may be necessary to address cyber assets associate with data communication between and ESP and a non-ESP, we do not believe the the use of a SAR is necessary. Perhaps revisisons to NERC Glossary of Terms or technical rationale are more appropriate means to provide guidance to industry. PNMR supports similar sentiment expressed in EEI comments.	

Likes 0	
Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	
Document Name	
Comment	
No comments received from Standard Owner or Subject Matter Experts	
Likes 0	
Dislikes 0	
Response	

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

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 around this SAR and do not feel it is needed in this form.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	
Document Name	
Comment	
No response received from Standard Owner or Subject Matter Experts	
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 agree that some points need clarification. Updating Standards seems extreme when other means are available. Means like Request For Interpretation. We agree with the clarification on protocol converters, but more than the topic of serial-to-IP such as converter location (inside/outside ESP?), is the converter an External Access Point (EAP)? How to address serial over copper to serial over fiber in the same facility? We agree with clarification on facilities with Medium and Low. Scenarios and/or use cases will help. We recommend this "industry need" include Generation.	

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 ISO/RTO Council Standards Review Committee (SRC).

Likes 0	
Dislikes 0	

Response

Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002

Answer	
Document Name	

Comment

The IRC SRC agrees that some points regarding protocol converters need clarification, which can be obtained through other means outside of the SAR process, such as through the Implementation Guidance processes.

Specifically, the SRC agrees that there needs to be clarification regarding implementation methods to meet compliance with protocol converters in the scenarios of serial over copper to serial over fiber connections.

The SRC also agrees that clarification of scenarios and use cases is needed regarding facilities with Medium and Low impact rated cyber assets.

The SRC recommends that the “industry need” portion of the SAR be expanded to include measures regarding Generation facilities, since the same or similar hardware architectures could also exist in those environments and to maintain consistency with other portions of the SAR.

Likes 0	
Dislikes 0	

Response

Sean Erickson - Western Area Power Administration - 1,6

Answer	
Document Name	

Comment	

· The potential scope of the proposed language on Page 3, “Consideration should also be given to other types of Cyber Assets used in the communication paths, such as routers and switches, along with ownership and management of the Cyber Assets as applicable to Functional Entity types defined in Appendix 5B of the Rules of Procedure” massively widens the scope to include all communication devices within a communications network. A communications network should be approached as an untrusted cloud, which CIP-005 already does. Overall the scope of the proposed “clarifications” is not clear.

· In the “Detailed Description” section, 1st paragraph, the language proposes enforcing an “authentication break” (undefined term) in the context of “system-to-system serial communication protocol converters”. Given system-to-system communication is not considered Interactive User Access, the term “authentication break” does not have a relation to this use case—it is uncler whether the proposal is for *authorization* or for *authentication*. This issue is also addressed in the 2022-INT-01 interpretation request.

· It is unclear what reliability or security risks are being mitigated by moving a protocol converter inside an ESP. In the proposed language, an ESP would only provide protection on the routable protocol side of the protocol converter, and not on the serial side of the converter, thereby only protecting one direction of the communication (routable -> serial). Moving the protocol converter inside the ESP brings the serial network inside the ESP, which would not be protected (serial -> routable).

· CIP-002 also provides the opportunity to implement a process to assist in the identification of high or medium BCS. Therefore, further clarification is not needed. This leads directly back to the previous comment about if the protocol converter being considered as part or the communication system. If that protocol converter has to be in the scope of CIP-002, then all communications components need to be. Instead of a SAR leading to a “one size fits all” solution, how the protocol converters are idetnfieid and protected should be assessed on a case-by-case basis given the various architectural options possible, and given the Responsible Entities process(es) for identifying and mitigating risks.

Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	

AZPS has no additional comments at this time.

Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	

Comment	
N/A	
Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 1,3,6	
Answer	
Document Name	
Comment	
Clarification on protocol converters since some are non-programmable devices. How to handle dial up connections or legacy non-IP communications. The topic of serial-to-IP such as converter location (inside/outside ESP?), is the converter an External Access Point (EAP)? How to address serial over copper to serial over fiber in the same facility?	
Likes 0	
Dislikes 0	
Response	

Brent Sessions - Western Area Power Administration - 3 - MRO,WECC	
Answer	
Document Name	
Comment	

- The potential scope of the proposed language on Page 3, "Consideration should also be given to other types of Cyber Assets used in the communication paths, such as routers and switches, along with ownership and management of the Cyber Assets as applicable to Functional Entity types defined in Appendix 5B of the Rules of Procedure" massively widens the scope to include all communication devices within a communications network. A communications network should be approached as an untrusted cloud, which CIP-005 already does. Overall the scope of the proposed "clarifications" is not clear.
- In the "Detailed Description" section, 1st paragraph, the language proposes enforcing an "authentication break" (undefined term) in the context of "system-to-system serial communication protocol converters". Given system-to-system communication is not considered Interactive User Access, the term "authentication break" does not have a relation to this use case—it is uncler whether the proposal is for *authorization* or for *authentication*. This issue is also addressed in the 2022-INT-01 interpretation request.
- It is unclear what reliability or security risks are being mitigated by moving a protocol converter inside an ESP. In the proposed language, an ESP would only provide protection on the routable protocol side of the protocol converter, and not on the serial side of the converter, thereby only protecting one direction of the communication (routable -> serial). Moving the protocol converter inside the ESP brings the serial network inside the ESP, which would not be protected (serial -> routable).
- CIP-002 also provides the opportunity to implement a process to assist in the identification of high or medium BCS. Therefore, further clarification is not needed. This leads directly back to the previous comment about if the protocol converter being considered as part or the communication system. If that protocol converter has to be in the scope of CIP-002, then all communications components need to be. Instead

of a SAR leading to a "one size fits all" solution, how the protocol converters are idetnfieid and protected should be assessed on a case-by-case basis given the various architectural options possible, and given the Responsible Entities process(es) for identifying and mitigating risks.	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - NA - Not Applicable	
Answer	
Document Name	
Comment	
CEHE has no additional comments.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
Generally, we agree that clarification would be needed for the categozation of some protocol converters. However, instead of updating the standard, a different mean, such as guideline, may be used to provide clarification on them. Examples of protocol converters (including but not limited to serial-to-ip converter) and use cases would be very helpful.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	
Document Name	
Comment	
Given that Project 2021-03 already has three other SARs, and the potential complexity of addressing this topic,a stand alone project should be	

considered. The potential CIP-005 implications of addressing this topic would be challenging to address in 2021-03.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Qu?bec TransEnergie - 1

Answer	
Document Name	

Comment

We agree that some points need clarification. Updating Standards seems extreme when other means are available. Means like Request For Interpretation.

We agree with clarification on protocol converters, but more than the topic of serial-to-IP such as converter location (inside/outside ESP?), is the converter an External Access Point (EAP)? How to address serial over copper to serial over fiber in the same facility?

We agree with clarification on facilities with Medium and Low. Scenarios and/or use cases will help.

We recommend this “industry need” include Generation.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

We agree that some points need clarification. Updating Standards seems extreme when other means are available. Means like Request For Interpretation.

We agree with clarification on protocol converters, but more than the topic of serial-to-IP such as converter location (inside/outside ESP?), is the converter an External Access Point (EAP)? How to address serial over copper to serial over fiber in the same facility?

We agree with clarification on facilities with Medium and Low. Scenarios and/or use cases will help.

We recommend this “industry need” include Generation.

Likes 0	

Dislikes 0	

Response

Alison MacKellar - Constellation - 5,6	
Answer	
Document Name	

Comment

Constellation aligns comments in agreement with Exelon.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	
Answer	
Document Name	

Comment

Regarding the SAR form's last question ("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."), NST disagrees with the answer given ("None"). While it may be true that no alternatives have been considered, we believe that if industry needs help with determining if and how protocol converters used for routable/serial communications links between BES Cyber Systems at different BES assets should be subject to CIP Requirements, a well-written guideline document would be a significantly better and less disruptive solution than an attempt to rewrite CIP-002.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	

Comment

Constellation aligns comments in agreement with Exelon Generation.

Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Comments received from Kinte Whitehead/Exelon

1. Do you agree with the proposed scope as described in the CIP-002 Communications Protocol Converters SAR? 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: Exelon has elected to align with EEI in response to this question.

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

   Comments:

Unofficial Comment Form

Project 2021-03 CIP-002

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-03 CIP-002** by **8 p.m. Eastern, Wednesday, July 12, 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

The purpose of Reliability Standard CIP-002 is to identify and categorize Bulk Electric System (BES) Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

The Standards Committee (SC) assigned a portion of the Project 2016-02 Standard Authorization Request (SAR) that relates to Transmission Owner Control Centers (TOCCs) to the Project 2021-03 Standard Drafting Team (SDT). The SAR portion is to review CIP-002 and evaluate standard revised Criterion 2.12 to categorize certain TOCCs performing Transmission Operator functions as medium impact based on an aggregate weighted value of their BES Transmission Lines. In addition, the SDT assisted NERC staff in meeting the directive from the NERC Board of Trustees (BOT) to conduct further study of the need to readdress the applicability of the Critical Infrastructure Protection Reliability Standards to theses Control Centers to support reliability. To help meet this directive and the scope of the SAR, the SDT initiated a field test. The SC approved the Field Test Plan on November 17, 2021. Three fields tests were conducted in 2022 and the final report was posted to the project page in January 2023.

The SDT is conducting an informal comment period to solicit feedback on proposed Standard language below that addresses:

- Control Center Definition
- New Definition for Data Center
- CIP-002-5.1a Criterion 2.12 with Exclusion process

Questions

Definitions:

Control Center: One or more ~~facilities hosting~~ *rooms where a responsible entity hosts* *operating personnel,* *as detailed below,* *that monitor and control the Bulk Electric System (BES) in real-time* ~~to perform the reliability tasks, including their associated data centers, of:~~ *, and any Data Centers intended to support the function of those rooms.*

1. *NERC certified personnel of a Reliability Coordinator*~~,~~ *having the capability or authority to control Facilities;*
2. *NERC certified personnel of a Balancing Authority*~~,~~ *having the capability or authority to control Facilities;*
3. *NERC certified personnel of a Transmission Operator* ~~for~~ *having the capability or authority to control Transmission Facilities at two or more locations*~~, or~~*;*
4. ~~a Generator Operator for generation Facilities at two or more locations.~~*Transmission Owner operating personnel having the capability to electronically control Transmission Facilities at two or more locations; or*
5. *Generation Operator operating personnel having the capability to electronically control generation Facilities at two or more locations.*

1. Control Center Definition: The SDT has proposed modifications to the definition of a Control Center based on ambiguity that surfaced during the Field Test. The crux of the ambiguity related to the existence of a TOCC and authority to control versus capability to control. As such, the SDT proposes to clearly specify that a Transmission Owner with the capability to electronically control Transmission Facilities at two or more locations has a Control Center. Further, the SDT is proposing to replace “to perform the reliability tasks” with specific language related to the capability or authority to control Facilities. Do you agree with the SDT’s approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

2. Control Center Definition: The SDT replaced “One or more facilities hosting operating personnel” with “One or more rooms where a responsible entity hosts operating personnel” to eliminate confusion between the terms ‘facility’ and NERC-defined ‘Facility’ that appears later in the definition of a Control Center. Further, the use of the term ‘rooms’ is intended to clarify that a Control Center may be one or more rooms within a larger building. Do you agree with the SDT’s approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

3. Control Center Definition: The SDT replaced “including their associated data centers” with “and any Data Centers intended to support the function of those rooms” to reference a recommended new defined term for Data Center and to clarify that an entity may have data centers that do not support the functions performed within the Control Center (e.g., data archival, etc.). Do you agree with the SDT’s approach? If not, please provide your rational and an alternate proposal.

☐ Yes
☐ No

Comments:

Data Center: A network of computing and storage resources that enable the use of shared applications in the exchange and management of data. The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers. The site could be located on-site within the entity’s physical building locations or could be in a virtual setting.

4. Data Center Definition: The SDT developed a definition for Data Center to support a common understanding of the term across the industry. Do you agree with the SDT’s approach and the proposed definition? If not please provide your rational and an alternate proposal.

☐ Yes
☐ No

Comments:

CIP-002.5-1a Criterion 2.12:

Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:

2.12. *Each Control Center or backup Control Center, operated by a registered Transmission Operator or owned by a registered Transmission Owner, ~~used to perform the functional obligations of the Transmission Operator~~ that is not already included in the High Impact Rating (H)~~,~~ above~~.~~, with an “aggregate weighted value” exceeding 6000 according to the table below, subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “ weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.*

Characteristics of a Line	*Weight Value per Characteristic*
Each BES Transmission Line less than 100kV	*100*
Each BES Transmission Line 100kV to 199kV	*250*
Each BES Transmission Line 200kV to 299kV	*700*
Each BES Transmission Line 300kV to 499kV	*1300*
Each BES Transmission Line 500kV and above	*0*
Each BES Transmission Line identified as part of a Cranking Path	*12000*

Exclusion:

Control Centers or backup Control Centers, operated by a registered Transmission Operator or owned by a registered Transmission Owner, with an "aggregate weighted value" between 6000 and 12000 are excluded provided that the BES Transmission system net export, as calculated for all BES Transmission Lines monitored and controlled by the Control Center or backup Control Center, does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The system net export is based on the hourly integrated power flow values over the course of the most recent two-year period.

5. Criterion 2.12: The BOT withdrew the previously proposed Reliability Standard CIP-002-6 in February 2021 and issued a resolution stating "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers to safeguard reliability, for the purpose of recommending further action to the Board". Pursuant to further study performed by the SDT via a Field Test, the SDT has determined that the previously proposed bright line of 6000 remains an appropriate initial criterion to differentiate between low impact and medium impact BES Cyber Systems, while safeguarding reliability. Further, the SDT recommends consideration of additional characteristics that may merit inclusion or exclusion. As such, the SDT has recommended revisions based on the previously proposed version of the standard. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

6. Criterion 2.12: The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". The intent of this addition was to align the language in the Medium Impact Rating section of CIP-002 Attachment 1 that applies to Control Centers with the language in the High Impact Rating section of CIP-002 Attachment 1. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

7. Criterion 2.12: The SDT proposes to remove the following language "used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines" in favor of explicitly identifying Control Centers that are "operated by a registered Transmission Operator or owned by a registered Transmission Owner". This eliminates the ambiguity that has been identified regarding the application of 'performing the reliability tasks of a Transmission Operator' to Transmission Owners and also eliminates duplication with language that already exists in the NERC defined term Control Center. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

8. Criterion 2.12: The SDT assigned a 'weight value per characteristic' to BES Transmission Lines less than 100kV given that the NERC defined term Bulk Electric System allows for specific inclusions of equipment that is less than 100kV. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

9. Criterion 2.12: The SDT has incorporated an additional characteristic, each BES Transmission Line identified as part of a Cranking Path, as an inclusion characteristic that would automatically ensure a Control Center is dispositioned above the bright line of 12000. This is based on the low probability, but high impact event where a cyber-compromised Control Center impacts restoration efforts following a widespread blackout. Further, systems and facilities critical to system restoration are specifically called out in the Low Impact Rating section of CIP-002 Attachment 1 which is indicative of reliability impacts. Other characteristics that were considered for inclusion such as Flowgates, IROLs and Remedial Action Schemes were ultimately excluded because the mere presence of these does not constitute a reliability risk to the BES and the ones that do impact reliability have already been addressed under CIP-002 Attachment 1 Criteria 2.6 and 2.9. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

10. Criterion 2.12: The SDT has developed an exclusion clause that would allow the BES Cyber Assets that are associated with a Control Center or backup Control Center to be classified as Low Impact instead of Medium Impact in the event that the calculated "aggregate weighted value" falls between 6000 and 12000, and the calculated BES Transmission system net export does not exceed 75 MW during non-Energy Emergency Alert conditions over the most recent two-year period. The 12000 cap on the "aggregate weighted value" is based on the equivalent of four stations with Medium impact BES Cyber Systems. The selection of the 75 MW threshold is based on the BES definition inclusion criterion for a generation plant. Energy Emergency Alert conditions were excluded given that an entity may be required to provide assistance, including load shed, to support the system. Do you agree with the SDT's approach and the proposed exclusion clause? If not, please provide your rationale and an alternate proposal.

    ☐ Yes
    ☐ No

    Comments:

Standards Announcement

Project 2021-03 CIP-002

Informal Comment Period Open through July 12, 2023

Now Available

A 30-day informal comment period for the **Project 2021-03 CIP-002**, is open through **8 p.m. Eastern, Wednesday, July 12, 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 2021-02 CIP-002 observer list" in the Description Box.

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

Comment Report

Project Name:	2021-03 CIP-002 | Transmission Owner Control Centers
Comment Period Start Date:	6/13/2023
Comment Period End Date:	7/12/2023
Associated Ballots:	

There were 49 sets of responses, including comments from approximately 79 different people from approximately 61 companies representing 7 of the Industry Segments as shown in the table on the following pages.

Questions

1. Control Center Definition: The SDT has proposed modifications to the definition of a Control Center based on ambiguity that surfaced during the Field Test. The crux of the ambiguity related to the existence of a TOCC and authority to control versus capability to control. As such, the SDT proposes to clearly specify that a Transmission Owner with the capability to electronically control Transmission Facilities at two or more locations has a Control Center. Further, the SDT is proposing to replace "to perform the reliability tasks" with specific language related to the capability or authority to control Facilities. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

2. Control Center Definition: The SDT replaced "One or more facilities hosting operating personnel" with "One or more rooms where a responsible entity hosts operating personnel" to eliminate confusion between the terms 'facility' and NERC-defined 'Facility' that appears later in the definition of a Control Center. Further, the use of the term 'rooms' is intended to clarify that a Control Center may be one or more rooms within a larger building. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

3. Control Center Definition: The SDT replaced "including their associated data centers" with "and any Data Centers intended to support the function of those rooms" to reference a recommended new defined term for Data Center and to clarify that an entity may have data centers that do not support the functions performed within the Control Center (e.g., data archival, etc.). Do you agree with the SDT's approach? If not, please provide your rational and an alternate proposal.

4. Data Center Definition: The SDT developed a definition for Data Center to support a common understanding of the term across the industry. Do you agree with the SDT's approach and the proposed definition? If not please provide your rational and an alternate proposal.

5. Criterion 2.12: The BOT withdrew the previously proposed Reliability Standard CIP-002-6 in February 2021 and issued a resolution stating "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers to safeguard reliability, for the purpose of recommending further action to the Board". Pursuant to further study performed by the SDT via a Field Test, the SDT has determined that the previously proposed bright line of 6000 remains an appropriate initial criterion to differentiate between low impact and medium impact BES Cyber Systems, while safeguarding reliability. Further, the SDT recommends consideration of additional characteristics that may merit inclusion or exclusion. As such, the SDT has recommended revisions based on the previously proposed version of the standard. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

6. Criterion 2.12: The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". The intent of this addition was to align the language in the Medium Impact Rating section of CIP-002 Attachment 1 that applies to Control Centers with the language in the High Impact Rating section of CIP-002 Attachment 1. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

7. Criterion 2.12: The SDT proposes to remove the following language "used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines" in favor of explicitly identifying Control Centers that are "operated by a registered Transmission Operator or owned by a registered Transmission Owner". This eliminates the ambiguity that has been identified regarding the application of 'performing the reliability tasks of a Transmission Operator' to Transmission Owners and also eliminates duplication with language that already exists in the NERC defined term Control Center. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

8. Criterion 2.12: The SDT assigned a 'weight value per characteristic' to BES Transmission Lines less than 100kV given that the NERC defined term Bulk Electric System allows for specific inclusions of equipment that is less than 100kV. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

9. Criterion 2.12: The SDT has incorporated an additional characteristic, each BES Transmission Line identified as part of a Cranking Path, as an inclusion characteristic that would automatically ensure a Control Center is dispositioned above the bright line of 12000. This is based on the low probability, but high impact event where a cyber-compromised Control Center impacts restoration efforts following a widespread blackout. Further, systems and facilities critical to system restoration are specifically called out in the Low Impact Rating section of CIP-002 Attachment 1 which is indicative of reliability impacts. Other characteristics that were considered for inclusion such as Flowgates, IROLs and Remedial Action Schemes were ultimately excluded because the mere presence of these does not constitute a reliability risk to the BES and the ones that do impact reliability have already been addressed under CIP-002 Attachment 1 Criteria 2.6 and 2.9. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

10. Criterion 2.12: The SDT has developed an exclusion clause that would allow the BES Cyber Assets that are associated with a Control Center or backup Control Center to be classified as Low Impact instead of Medium Impact in the event that the calculated "aggregate weighted value" falls between 6000 and 12000, and the calculated BES Transmission system net export does not exceed 75 MW during non-Energy Emergency Alert conditions over the most recent two-year period. The 12000 cap on the "aggregate weighted value" is based on the equivalent of four stations with Medium impact BES Cyber Systems. The selection of the 75 MW threshold is based on the BES definition inclusion criterion for a generation plant. Energy Emergency Alert conditions were excluded given that an entity may be required to provide assistance, including load shed, to support the system. Do you agree with the SDT's approach and the proposed exclusion clause? If not, please provide your rationale and an alternate proposal.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Nick Fogleman	Prairie Power, Inc.	1	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
					Bill Pezalla	Old Dominion Electric Cooperative	3,4	RF
					Marcus Perkins	Southern Maryland Electric Cooperative	3	RF
Eversource Energy	Joshua London	1,3		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
California ISO	Monika Montez	2	WECC	ISO/RTO Council Standards	Monika Montez	CAISO	2	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF

				Review Committee (SRC) Project 2021-03 CIP-002 TOCC	Kathleen Goodman	ISO-NE	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Elizabeth Davis	PJM	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
BC Hydro and Power Authority	Patricia Robertson	1,3,5	WECC	BC Hydro Balloters	Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
Western Electricity Coordinating Council	Steven Rueckert	10		WECC CIP	Steve Rueckert	WECC	10	WECC
					Morgan King	WECC	10	WECC
					Deb McEndaffer	WECC	10	WECC
					Tom Williams	WECC	10	WECC

1. Control Center Definition: The SDT has proposed modifications to the definition of a Control Center based on ambiguity that surfaced during the Field Test. The crux of the ambiguity related to the existence of a TOCC and authority to control versus capability to control. As such, the SDT proposes to clearly specify that a Transmission Owner with the capability to electronically control Transmission Facilities at two or more locations has a Control Center. Further, the SDT is proposing to replace "to perform the reliability tasks" with specific language related to the capability or authority to control Facilities. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Sunflower does not believe a modification to the Control Center definition is required.	
Likes 0	
Dislikes 0	
Response	

Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy thanks the Drafting team for the work to create these proposed modifications and for the opportunity to provide feedback through an informal comment period. Duke Energy does not believe that there is a substational level of ambiguity on what currently constitutes a Control Center, but recognizes the intention to clarify expectations for inclusion. If broader industry stakeholders also support that there is an unacceptable level of ambiguity, we would recommend that "authority" to control be removed from the definition, as "capability" to control would be the new minimum. Capability should capture entities that have the authority to control, as those with the authority should have the capability. Below is our recommended definition for consideration if the Standard Drafting Team decides to continue modifying the definition:

Control Center:

One or more physical spaces where a responsible entity hosts operating personnel, as detailed below, that monitor and/or control Facilities on the Bulk Electric System (BES) in Real-time, and any Data Centers intended to support the function of those spaces.

1. *NERC certified personnel of a Reliability Coordinator, having the capability to control Facilities;*
2. *NERC certified personnel of a Balancing Authority, having the capability to control Facilities;*
3. *NERC certified personnel of a Transmission Operator having the capability to control Transmission Facilities at two or more locations;*
4. *Transmission Owner operating personnel having the capability to electronically control Transmission Facilities at two or more locations; or*

5. *Generation Operator operating personnel having the capability to electronically control generation Facilities at two or more locations.*

Likes 0	
Dislikes 0	

Response

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	No
Document Name	

Comment

BHE views the proposed modifications to the Control Center definition as a positive move in the right direction that does enhance clarity. We believe the proposed definition can be further clarified with the following suggested wording:

Control Center: One or more designated locations where a responsible entity hosts operating personnel, as detailed below, that monitor and control the Bulk Electric System (BES) with Real-time Assessment, and any part of data centers intended to support the BES reliability function of those locations.

Regarding the 5 categories of operating personnel, in all cases BHE requests replacing “capability or authority” with “capability and authority,” as anyone with authority but not capability would not merit inclusion as operating personnel.

Likes 0	
Dislikes 0	

Response

Matt Lewis - Lower Colorado River Authority - 1,5

Answer	No
Document Name	

Comment

We are not sure of the significance of the word “electronically control”. Is this to distinguish the TO/GO who uses a SCADA EMS to electronically control field devices versus an entity who has to manually/locally control? More clarity in the wording would help.

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 comments of EEI.

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	
Comment	

Xcel Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	No
Document Name	
Comment	

BHE views the proposed modifications to the Control Center definition as a positive move in the right direction that does enhance clarity. We believe the proposed definition can be further clarified with the following suggested wording:

Control Center: One or more designated locations where a responsible entity hosts operating personnel, as detailed below, that monitor and control the Bulk Electric System (BES) with Real-time Assessment, and any part of data centers intended to support the BES reliability function of those locations.

Rationale:

- “designated locations” is preferable to “rooms” as it provides greater flexibility and resolution.
- “with Real-time Assessment” is what we understand “in real-time" to intend.
- “part of data centers” to allow greater resolution to the applicable locations within a data center, which we do not believe requires a definition.
- “BES reliability function” to ensure only the relevant parts of a data center are within scope.

Regarding the 5 categories of operating personnel, in all cases BHE requests replacing “capability or authority” with “capability and authority,” as anyone with authority but not capability would not merit inclusion as operating personnel.

Likes 0	
Dislikes 0	

Response

Byron Booker - Oncor Electric Delivery - 1

Answer	No
Document Name	

Comment

Oncor supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5

Answer	No
Document Name	

Comment

We recommend changing from “having the capability or authority to control Facilities;” to “having the capability and authority to control Facilities;”

The numbered parts of the Control Center definition adds the phrase “having the capability or authority to control Facilities;”

In the example “NERC certified personnel of a Reliability Coordinator, having the capability or authority to control Facilities;” due to the “or,” the definition of Control Center would follow an employee who has the authority to control facilities, regardless of capability, to whatever room they reside in.

Likes 0	
Dislikes 0	

Response

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

Although EEI appreciates SDT efforts to remove existing ambiguity surrounding what constitutes a Control Center, the proposed revisions appear to add to that ambiguity and may expand the scope of what constitutes a control center beyond what was intended. To address our concerns, we suggest the following for consideration:

Proposed Control Center Definition

The location(s) where the processes, procedures, tools, and training required to meet the reliability obligations under the NERC Organization Certification Process are performed. In addition, location(s) where the personnel and tools used to monitor and that have the capability to control, in Real-time, Facilities at two or more other locations.

Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	No
Document Name	
Comment	

SPP appreciates the SDT's proposed changes to clarify the Control Center definition. The current draft creates more confusion than clarity on the scope of a Control Center and may have inadvertently incurred "scope creep" for the Reliability Coordinator (RC) and Balancing Authority (BA) reliability functions.

SPP proposes the following draft to help simplify the Control Center definition (with the focus of these proposed changes on RC and BA responsibilities):

Control Center: One or more rooms where a Responsible Entity hosts operating personnel, as detailed below, that either (i) monitor and control, or (ii) monitor and direct action for the Bulk Electric System (BES) in real-time, and any Data Centers intended to support the function of those rooms:

1. NERC certified personnel of a Reliability Coordinator, having the authority to monitor and/or direct action for the reliability of the BES;

2. NERC certified personnel of a Balancing Authority, having the authority to monitor and/or direct action for the reliability of the BES;

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG agrees with the NPCC/RSC's comments.

Additionally, the definition of control center should be 'locations' and not 'rooms'. It is possible a control center is a whole building or may even be virtual and not just a room.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5

Answer	No
Document Name	

Comment

We recommend changing from "*having the capability or authority to control Facilities*;" to "*having the capability and authority to control Facilities;*"

The numbered parts of the Control Center definition adds the phrase "*having the capability or authority to control Facilities;*"

In the example "*NERC certified personnel of a Reliability Coordinator, having the capability or authority to control Facilities;*" due to the "*or,*" the definition of Control Center would follow an employee who has the authority to control facilities, regardless of capability, to whatever room they reside in.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1,3, Group Name Eversource

Answer	No
Document Name	

Comment

Eversource agrees with the comments of the NPCC RSC.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 5,6

Answer	No
Document Name	

Comment

Constellation does not support the proposed definition of Control Center. The proposed definition indicates operating personnel should have control "or" authority, but it is important for operating personnel to have the capability to control AND also have authority because having the capability to control requires having internal controls in place and having authorization is one of those internal controls. Understanding the BES reliability operating functions provides the foundation for classification of BES Cyber Systems. Reducing the definition to monitor and control may lead to confusion in methods used to classify BES Cyber Systems. We recommend keeping some reference to BROS function in the Control Center definition.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FirstEnergy believes the suggested definition be narrowed for its intent toward CIP-002. We offer the suggested language :

Control Center: One or more rooms where a responsible entity hosts operating personnel, as detailed below, that monitor and control the Bulk Electric System (BES) in real-time, and any Data Centers **containing BES Cyber Assets that comprise BES Cyber Systems**.

1. NERC certified personnel of a Reliability Coordinator, having the capability or authority to control Facilities;

2. NERC certified personnel of a Balancing Authority, having the capability or authority to control Facilities;

3. NERC certified personnel of a Transmission Operator for having the capability or authority to control Transmission Facilities at two or more locations;

4. Transmission Owner operating personnel having the capability to electronically control Transmission Facilities at two or more locations; or

5. Generation Operator operating personnel having the capability to electronically control generation Facilities at two or more locations.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	No
Document Name	

Comment

MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF) and ACES.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5,6

Answer	No
Document Name	

Comment

Constellation does not support the proposed definition of Control Center. The proposed definition indicates operating personnel should have control "or" authority, but it is important for operating personnel to have the capability to control AND also have authority because having the capability to control requires having internal controls in place and having authorization is one of those internal controls. Understanding the BES reliability operating functions provides the foundation for classification of BES Cyber Systems. Reducing the definition to monitor and control may lead to confusion in methods used to classify BES Cyber Systems. We recommend keeping some reference to BROS function in the Control Center definition.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Justin Kuehne - AEP - 3,5,6	
Answer	No
Document Name	
Comment	

AEP does not recommend the inclusion of the Transmission Owner in #4 of the Control Center definition. Any operating personnel who have the capability to control Transmisssion Facilities from a Control Center are required to be NERC certified Transmission Operators thus requiring the entity to be registered as a Transmission Operator. As a result, the inclusion of Transmission Owner is confusing, as we feel the Transmission Operator language in #3 adequately covers what is described in #4.

Additionally, AEP recommends the following language for #5:

"5. Generator Operator (GOP) operating personnel having the capability to electronically control generation Facilities at two or more locations."

Generation Operator is not a NERC defined term, but Generator Operator is. As such, AEP recommends the defined function replace what is proposed.

Likes 0	
Dislikes 0	
Response	

Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters	
Answer	No
Document Name	
Comment	

Proposed modifications to the definition of Control Centre don't align with CIP-002.5.1a Attachment 1 high and medium impact Control Center criteria 1.1 to 1.4 and 2.11 to 2.13 as these Control Centre criteria still use "perform functional obligations" language which is equivalent to "to perform the reliability tasks" SDT tried to replace. For instance, in a GOP control room, the operating personnel are capable of controlling generating units at two generation plants, but they don't perform GOP obligations that are only taken by the GOP System Operators. Even though this GOP control room would become a Control Centre based on the modified Control Centre definition, it wouldn't meet any high or medium Control Center impact rating criteria thus only becoming a low impact Control Center.
The language around "the capability to electronically control Transmission Facilities at two or more locations has a Control Center" is vague and could encompass facilities and locations that definitely should not be considered control centers.
The SDT is requested to consider not removing 'reliability-related tasks' from the currently defined terms as this will further clarifiy who is 'operating personnel'.
BCH also seeks clarity on the use of the word 'capability'. SDT shoud allow for provisions where protections have been implemented that reduce/impair "capability", but there still exists the possibility without those protections.
The inclusion of point 4 and 5 (in Control Center Defintion) for consideration of operating personnel (i.e. technicians and electricians may qualify) would effectively turn any generation control room that has the capability to electronically control a local and remote BES asset into a Control Center. SDT to provide some use cases and exmaples to clarify this.
Recommendations:
1)Modify CIP-002 Attachment 1 criteria 1.1 to 1.4 and 2.11 to 2.13 to change "perform functional obligations" to "control Facilities".
2)Provide calrity of the use term 'operating personnel' in item 4 and 5 of Control Center definition and use of the term 'capability' with use cases and examples

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

SRP agrees with Berkshire Hathaway Energy (BHE) that all NERC certified personnel or operating personnel should have both the capability **and** authority to control facilities.

Proposed Definition- Control Center: One or more **designated** rooms where a responsible entity hosts **NERC certified or** operating personnel, as detailed below, that monitor and control the Bulk Electric System (BES) in real-time, and any **part of** Data Centers intended to support the function of those **designated** rooms.

Likes 0	
Dislikes 0	

Response

VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3,4,5

Answer	No
Document Name	

Comment

Instead of "Capability OR authority," SVP suggests "capability and authority" or just "capbility."

Likes 0	
Dislikes 0	

Response

Alain Mukama - Hydro One Networks, Inc. - 1,3

Answer	No
Document Name	

Comment

Suggest to change "having the capability and authority to control" in order to ensure that the room(s) can only be considered a Control Center when the

personnels control with authority.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) has concern with the change to Generation Operator in #5; SIGE suggests using the defined term Generator Operator.

Also, in the Control Center definition, SIGE suggests removing “as detailed below” and including “As used in this definition, the term “operating personnel” means the following” as suggested below.

Control Center: One or more control rooms where a responsible entity hosts operating personnel, that monitor and control the Bulk Electric System (BES) in real-time including their associated data centers. As used in this definition, the term “operating personnel” means the following:

1. *NERC certified personnel of a Reliability Coordinator, having the capability or authority to control Facilities;*
2. *NERC certified personnel of a Balancing Authority, having the capability or authority to control Facilities;*
3. *NERC certified personnel of a Transmission Operator having the capability or authority to control Transmission Facilities at two or more locations;*
4. *Transmission Owner operating personnel having the capability to electronically control Transmission Facilities at two or more locations; or*
5. *Generator Operator operating personnel having the capability to electronically control generation Facilities at two or more locations.*

Likes 0	
Dislikes 0	
Response	
Kevin Lyons - Central Iowa Power Cooperative - 1	
Answer	No
Document Name	
Comment	

On item #4, CIPCO suggests adding “BES” in front of “Transmission Facilities.” Although the NERC definition of Facility pertains to Bulk Electric System Elements, the definition of Transmission omits any mention of the BES. Adding “BES” removes the potential for ambiguity in the same manner that replacing “facilities” with “rooms” does.

Likes 0	
Dislikes 0	

Response

Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC (CEHE) suggests using the defined term “Generator Operator” in place of “Generation Operator” in #5. Also, in the Control Center definition, CEHE suggests removing “as detailed below” and including “As used in this definition, the term “operating personnel” means the following.”

In addition, CEHE recommends adding “control” in front of “rooms”, as to restrict the term “control rooms” to only purpose-built spaces that monitor and control BES Cyber Assets of the BES. CEHE recommends the following definition of Control Center:

Control Center: *One or more control rooms where a responsible entity hosts operating personnel, that monitor and control the Bulk Electric System (BES) in real-time including their associated data centers. As used in this definition, the term “operating personnel” means the following:*

1. *NERC certified personnel of a Reliability Coordinator, having the capability or authority to control Facilities;*
2. *NERC certified personnel of a Balancing Authority, having the capability or authority to control Facilities;*
3. *NERC certified personnel of a Transmission Operator having the capability or authority to control Transmission Facilities at two or more locations;*
4. *Transmission Owner operating personnel having the capability to electronically control Transmission Facilities at two or more locations; or*
5. *Generator Operator operating personnel having the capability to electronically control generation Facilities at two or more locations.*

Likes 0	
Dislikes 0	

Response

John Daho - MEAG Power - 1,3 - SERC

Answer	No
Document Name	

Comment

Since operating personnel is not a defined term in the Glossary of Terms, the criteria for Transmission Owner as currently proposed could lead to confusion on applicability. Language that includes the term BES when referencing the capability to electronically control Transmission Facilities is recommended. Proposed update for 4) Transmission Owner: 'Transmission Owner operating personnel that monitor and control the BES in real-time and having the capability to electronically control the BES at two or more Transmission Facilities'. Similar update is suggested for Generation 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	No
Document Name	

Comment

ACES suggests that, instead of modifying all the language, add: "A Transmission Owner with the capability to electronically control Transmission Facilities at two or more locations" as a criterion for Control Center qualification. ACES believes less is more in this case.

Likes 0	
Dislikes 0	

Response

Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC

Answer	No
Document Name	

Comment

The SRC supports the proposed modifications to the definition of a Control Center but suggests the drafting team consider adding **"or monitor and direct action"** to the first sentence as follows:

Control Center: One or more rooms where a responsible entity hosts operating personnel, as detailed below, that monitor and control **"or monitor and direct action"** for the Bulk Electric System (BES) in real-time, and any Data Centers intended to support the function of those rooms.

Likes 0	
Dislikes 0	

Response

Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF

Answer	No
Document Name	

Comment	
ITC supports the comments submitted by EEI	
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 responses of the Edison Electric Institute and MRO NSRF for question #1.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	No
Document Name	
Comment	
Exelon is in support of EEI response to this question.	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	
Answer	No
Document Name	
Comment	

NST believes the phrase, "having the capability or authority to control" should be changed to "having the capability *and* authority to control."

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Ameren supports EEI's comments on this question.

Likes 0	
Dislikes 0	

Response

Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

AES Clean Energy support Duke Energy's comments - see below.

"Duke Energy thanks the Drafting team for the work to create these proposed modifications and for the opportunity to provide feedback. Duke Energy does not believe that there is a substational level of ambiguity on what currently constitutes a Control Center, but recognizes the intention to clarify expectations for inclusion. If broader industry stakeholders also support that there is an unacceptable level of ambiguity, we would recommend that “authority” to control be removed from the definition, as “capability” to control would be the new minimum. Capability should capture entities that have the authority to control, as those with the authority should have the capability. Below is our recommended definition for consideration if the Standard Drafting Team decides to continue modifying the definition:

Control Center:

One or more physical spaces where a responsible entity hosts operating personnel, as detailed below, that monitor and/or control Facilities on the Bulk Electric System (BES) in Real-time, and any Data Centers intended to support the function of those spaces.

1. *NERC certified personnel of a Reliability Coordinator, having the capability to control Facilities;*
2. *NERC certified personnel of a Balancing Authority, having the capability to control Facilities;*
3. *NERC certified personnel of a Transmission Operator having the capability to control Transmission Facilities at two or more locations;*

4. *Transmission Owner operating personnel having the capability to electronically control Transmission Facilities at two or more locations; or*
5. *Generation Operator operating personnel having the capability to electronically control generation Facilities at two or more locations.*"

Likes 0	
Dislikes 0	
Response	
Jessica Meisel-Tognacci - NextEra Energy - Florida Power and Light Co. - 1 - SERC	
Answer	No
Document Name	
Comment	
NextEra Energy supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	

The standard drafting team has done a very detailed and careful review and accounted for many cases in the development of the definition. The team is using a good approach. Manitoba Hydro suggests that the definition can be clarified by highlighting in case 4 and 5 that they apply only in the case where multiple Facilities are controlled, in order to clarify that operating personnel can control a single Facility that spans multiple physical locations (for example, two ends of a transmission line). Additional clarification for Inverter Based Resources could improve clarity with respect to location as the individual generators span multiple physical locations. The following is suggested:

Transmission Owner operating personnel having the capability to electronically control two or more Transmission Facilities at two or more locations; or

Generation Operator operating personnel having the capability to electronically control two or more generation Facilities at two or more interconnections with the BES.

Likes 0	
Dislikes 0	

Response	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Eddleman - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	
Document Name	
Comment	

Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	
Response	

2. Control Center Definition: The SDT replaced “One or more facilities hosting operating personnel” with “One or more rooms where a responsible entity hosts operating personnel” to eliminate confusion between the terms ‘facility’ and NERC-defined ‘Facility’ that appears later in the definition of a Control Center. Further, the use of the term ‘rooms’ is intended to clarify that a Control Center may be one or more rooms within a larger building. Do you agree with the SDT’s approach? If not, please provide your rationale and an alternate proposal.

Jessica Meisel-Tognacci - NextEra Energy - Florida Power and Light Co. - 1 - SERC	
Answer	No
Document Name	
Comment	
NextEra Energy supports EEI’s comments.	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
AES Clean Energy support Duke Energy's comments - see below: "While Duke Energy appreciates the attempts to clarify between the use of a defined and undefined term, Duke Energy did not experience confusion between the term facilities and the defined term Facilities. While we can appreciate that it is an area some may find confusing, it appears that the new “rooms” language introduces more ambiguity than facilities. We suggest that the drafting team consider “physical spaces” to better accommodate the variety of locations that an entity may house operators."	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	

Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	
Answer	No
Document Name	
Comment	
NST agrees with replacing "facilities" with "rooms" but sees no need for further revision of the introductory words, so we recommend changing to say, "One or more rooms hosting operating personnel,..."	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	No
Document Name	
Comment	
Exelon suggest the use of "room" along with the definition following as to what qualifies it to be part of a Control Center. The definition should not change drastically from what it already is, but for clarity, to possibly eliminate some data centers that are technically "associated" but do not actively support the Control Center (e.g. are used for data archival only).	
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 response of the Edison Electric Institute for question #2.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	No
Document Name	
Comment	
ITC supports the comments submitted by EEI	
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	
ACES believes industry participants understand the location and scope of Control Centers and that this definition does not need to be modified. If the term “facility” must be replaced, ACES suggests a word other than “rooms”, as it seems to make the definition more ambiguous than the current definition.	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CEHE supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	No
Document Name	
Comment	
Because the distinction between lower-case "facility" and uppercase "Facility" has been well-established over time, further clarification is not necessary.	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters	
Answer	No
Document Name	
Comment	

SDT is requested to avoid use of the word 'rooms' as this is confusing and can mix up with other rooms such as the communication rooms and operator training rooms. The SDT should consider a definition of Control Centre Facility to define the Control Center that could be made up of multiple rooms that are either part of, or not part of a Control Centre. Additionally, the SDT is requested to consider not removing ‘reliability-related tasks from defined terms as this further clarifies who is 'operating personnel'. Recommendation: Changing the “rooms” to “control rooms”.	
Likes 0	
Dislikes 0	
Response	
Justin Kuehne - AEP - 3,5,6	
Answer	No
Document Name	
Comment	
AEP agrees that the use of “facility” added confusion in the current definition. However, AEP recommends the word “rooms” be replaced with “secure areas defined by a physical security perimeter”. This language allows for more flexibility in how the space of a Control Center is defined.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	
The terms Facility and facility are not confusing and should remain in the definition. The term “room” is ambiguous and could create confusion with the term "control room" that is used broadly at generation resources. The terms “location”, “space”, “Facility”, “building” could all be used in place of room. The operating personnel are the key to control capability, not the room. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No
Document Name	
Comment	
Refer to response to Q1.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
The terms Facility and facility are not confusing and should remain in the definition. The term “room” is ambiguous and could create confusion with the term "control room" that is used broadly at generation resources. The terms “location”, “space”, “Facility”, “building” could all be used in place of room. The operating personnel are the key to control capability, not the room. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource agrees with the comments of the NPCC RSC.	
Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Comment

We agree that the use of the terms “facilities” and “Facilities” can create uncertainty in the meaning of the definition but believe that the proposed changes are too specific to the architecture of the building and does not provide clarity on what is meant by “hosting”.

For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

1) {C}If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers but no one is assigned to that desk, is the engineering office a Control Center? or

2) {C}If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or

3) {C}If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or

4) {C}If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center?

5) {C}If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a Control Center?

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG agrees with the NPCC/RSC'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 that changing the uncapitalized term facility to room eliminates confusion. To address this concern, “control room” should be added in front of room to narrow what might be considered a Control Center.	
Likes 0	
Dislikes 0	
Response	

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	

We agree that the use of the terms “facilities” and “Facilities” can create uncertainty in the meaning of the definition but believe that the proposed changes are too specific to the architecture of the building and does not provide clarity on what is meant by “hosting”.

For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

1) If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers but no one is assigned to that desk, is the engineering office a Control Center? or

2) If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or

3) If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or

4) If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center?

5) If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a Control Center?

Likes 0	
Dislikes 0	
Response	

Byron Booker - Oncor Electric Delivery - 1	
Answer	No
Document Name	
Comment	

Oncor supports the comments submitted by EEI.

Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	No
Document Name	

Comment
BHE agrees “rooms” is an improvement over “facilities” but would prefer the more flexible and more precise where needed term “designated locations.”

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	No
Document Name	

Comment
Xcel Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment
Southern Company supports the comments of EEI.

Likes 0	
Dislikes 0	

Response

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	No
Document Name	

Comment	
BHE agrees “rooms” is an improvement over “facilities” but would prefer the more flexible and more precise where needed term “designated location	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
While Duke Energy appreciates the attempts to clarify between the use of a defined and undefined term, Duke Energy did not experience confusion between the term facilities and the defined term Facilities. While we can appreciate that it is an area some may find confusing, it appears that the new “rooms” language introduces more ambiguity than facilities. We suggest that the drafting team consider “physical spaces” to better accommodate the variety of locations that an entity may house operators.	
Likes 0	
Dislikes 0	
Response	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Sunflower does not believe a modification to the Control Center definition is required.	
Likes 0	
Dislikes 0	
Response	
Tony Eddleman - Nebraska Public Power District - 1,3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Lyons - Central Iowa Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
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	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO

Answer	
Document Name	

Comment
Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	

Response

3. Control Center Definition: The SDT replaced "including their associated data centers" with "and any Data Centers intended to support the function of those rooms" to reference a recommended new defined term for Data Center and to clarify that an entity may have data centers that do not support the functions performed within the Control Center (e.g., data archival, etc.). Do you agree with the SDT's approach? If not, please provide your rational and an alternate proposal.

Paul Mehlhaff - Sunflower Electric Power Corporation - 1

Answer	No
Document Name	

Comment

Sunflower does not believe a modification to the Control Center definition is required.

Likes 0	
Dislikes 0	

Response

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	No
Document Name	

Comment

BHE understands the approach but would further refine it to not define data centers and to ensure only applicable portions of the data center supporting the BES reliability functions of the control center.

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 comments of EEI.

Likes 0	
Dislikes 0	

Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	No
Document Name	
Comment	
BHE understands the approach but would further refine it to not define data centers and to ensure only applicable portions of the data center supporting the BES reliability functions of the Control Center.	
Likes 0	
Dislikes 0	
Response	
Byron Booker - Oncor Electric Delivery - 1	
Answer	No
Document Name	
Comment	
Oncor supports the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	

The terms “any” and “intended to support the function” could be interpreted to include data centers that are not owned, operated or controlled by the entity.

The phrase “the function of those rooms” does not limit the function to only those that impact the BES.

Below, we recommend a new term instead of Data Center. Consistent with that recommendation, we start proposing an alternative approach here.

Data Center: A network of computing and storage resources that enable the use of shared applications in the exchange and management of data. The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers. The site could be located on-site within the entity’s physical building locations or could be in a virtual setting.

Likes 0	
Dislikes 0	
Response	

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	

Cleco agrees with EEI comments.

Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	No
Document Name	
Comment	

Tri-State would like to know if the SDT rafting team considered future state of cloud based devices in the definition of Data Center?

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 this approach. The proposed definition for Data Center is too broad and has the potential of expanding the scope of a control center much further than is needed. Also, as responsible entities adopt virtualization and control center data move into the cloud, such a definition will impact their ability to utilize these solutions.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG agrees with the NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	
The terms “any” and “intended to support the function” could be interpreted to include data centers that are not owned, operated or controlled by the entity.	

The phrase “the function of those rooms” does not limit the function to only those that impact the BES.

Below, we recommend a new term instead of Data Center. Consistent with that recommendation, we start proposing an alternative approach here

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1,3, Group Name Eversource

Answer	No
Document Name	

Comment

Eversource agrees with the comments of the NPCC RSC.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 5,6

Answer	No
Document Name	

Comment

Constellation does not support changing the wording for data centers. Expanding the wording of data centers in the definition of Control Centers may create an unintended broad impact on the Control Centers. The language “intended to support the function of the rooms” is not clear and overly broad. Data centers support the BES reliability operating services. If the definition were to expand it could impact, unnecessarily, third party managed data centers or cloud-based services that may support a reliability function. The proposed definition of data center also may limit future technological efficiencies used to implement CIP-004-7 & CIP-011-3. Constellation recommends maintaining the existing control center wording, “including their associated data centers.”

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	No
Document Name	
Comment	
We believe the definition of Control Center should not include the term Data Center to clarify applicable assets under CIP-002.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by the MRO NERC Standards Review Forum (NSRF) and ACES.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	No
Document Name	
Comment	
Constellation does not support changing the wording for data centers. Expanding the wording of data centers in the definition of Control Centers may create an unintended broad impact on the Control Centers. The language "intended to support the function of the rooms" is not clear and overly broad. Data centers support the BES reliability operating services. If the definition were to expand it could impact, unnecessarily, third party managed data centers or cloud-based services that may support a reliability function. The proposed definition of data center also may limit future technological efficiencies used to implement CIP-004-7 & CIP-011-3. Constellation recommends maintaining the existing control center wording, "including their associated data centers." Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	

Response	
Justin Kuehne - AEP - 3,5,6	
Answer	No
Document Name	
Comment	

AEP supports the intent of the added Data Center definition within the Control Center definition. However, AEP recommends clarifying that a NERC defined Data Center is intended to support NERC functions referenced in the Control Center definition to further remove ambiguity regarding its purpose.

Additionally, AEP recommends including the aforementioned “secure area” language to the end of the definition.

Recommended language includes: *“and any Data Centers intended to support the Reliability Coordinator, Balancing Authority, Transmission Operator, or Generator Operator function of those secure areas”.*

Likes 0	
Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters	
Answer	No
Document Name	
Comment	

The Data Center definition should have a linkage to the Control Centre and should be at a physical location regardless of whether it is a virtual setting such as a virtual server.
The sentence about "any Data Centers intended to support the function of those rooms" is very vague and could be used to include anything used directly or indirectly by operators in the control rooms. Including facilities that have nothing to do with the BES. BCH proposes that the original wording should be kept.
Recommendations:
BCH proposes the following wording for Data Center definiton:
“A physical location hosting physical or virtual severs that are connected to one or more Control Centers through networking and communication equipment such as routers, switches and firewalls to store, transfer and exchange real-time BES data and share associated applications with Control Centers.”

Likes 0	
Dislikes 0	
Response	

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

Manitoba Hydro thanks the drafting team for their detailed work on defining both a Control Center and Data Center. The effort to clarify the definitions is the correct direction. Using a separate definition for Data Center could be problematic as the definition of a Data Center would need to be generic, describing any Data Center whether it is used for SCADA EMS systems or business systems. However specifically relating to Control Centers, only the Control Center Data Center that actually processes SCADA EMS data is in scope. Manitoba Hydro suggests the following definition change, going back to the original approach of having one definition:

Control Center: One or more rooms where a responsible entity hosts operating personnel, as detailed below, that monitor and control the Bulk Electric System (BES) in real-time, and any data center rooms housing Cyber Assets that process Real-Time monitoring data for display in the Control Center or perform Real-Time Assessment.

Likes 0	
Dislikes 0	
Response	

Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Q3/Q4. SRP agrees with the approach to distinguish between data centers (or parts of data centers) that do and do not support the functions performed within the Control Center. However, in alignment with Duke, SRP does not see the need to define a data center as we don't believe there is ambiguity with what constitutes a data center. Further, the proposed definition of Control Center already clarifies that it is only addressing data centers (or parts of) that support the real-time functions performed within these designated rooms.

Likes 0	
Dislikes 0	
Response	

VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	No
Document Name	
Comment	

SVP agrees with AEP's comments.

Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Kevin Lyons - Central Iowa Power Cooperative - 1	
Answer	No
Document Name	
Comment	
CIPCO is concerned that the proposed definition does not sufficiently differentiate between business and operational systems and therefore allows for potential scope creep. CIPCO suggests two possible alternatives: 1) specifying within the new definition of Data Center "in the exchange and management of data *used in the operation and control of the Bulk Electric System*…", or 2) leave the text of the definition as-is but change the term to "BES Data Center." A third option would be to change both the definition and the term as described here.	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE does not agree with the proposed Control Center definition and the use of the term "rooms." CEHE believes that the term "rooms" is too broad	

and could be misinterpreted to include anywhere from which physical or electronic access to a BES Cyber System is permitted. To prevent this type of misinterpretation, CEHE suggests adding “control” in front of “rooms,” to restrict the definition of “control rooms” to only purpose-built spaces that monitor and control BES Cyber Assets of the BES. CEHE does not see the need to define “Data Center,” as this term is well understood in the industry. Also, CEHE feels that it would be difficult to prove the intent of “any Data Centers intended to support the function of those rooms,” as the definition is proposed. Furthermore, CEHE supports maintaining “the associated data centers” from the original language.

Likes 0	
Dislikes 0	

Response

John Daho - MEAG Power - 1,3 - SERC

Answer	No
Document Name	

Comment

Suggested update from ‘and any Data Centers intended to support the function of those rooms’

to ‘and any Data Centers or designated spaces within the Data Centers intended to support the function of those rooms’.

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 words “intended” and “support the function” allow for potential scope creep by including more physical locations. There are many Data Centers supporting the function of the BES external to the scope of BCS such as telecommunication Data Centers. “Including their associated data centers” has been used in the industry for years and ACES does not believe there is ambiguity in this definition.

Likes 0	
Dislikes 0	

Response

Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF

Answer	No

Document Name	
Comment	
ITC supports the comments submitted by EEI	
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 responses of the Edison Electric Institute and MRO NSRF for question #3.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	No
Document Name	
Comment	
Exelon suggests including “reliability” in front of functions. This might help to limit scope. (Separately, consider Virtualization questions – these may need to be addressed separately).	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	
Answer	No
Document Name	
Comment	

NST is not aware of a pressing need to change "associated data centers." However, if the SDT is convinced there is such a need, we recommend changing the proposed language to read, "and any data centers that provide necessary computing resources." The use of lower case, "data centers" is intentional.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Ameren supports EEI's comments on this question.

Likes 0	
Dislikes 0	

Response

Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

AES Clean Energy supports Duke Energy's alternate proposal - see below:

"*Data Center: A network of computing and storage resources that enable the use of shared applications in the exchange and management of data. The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers. The site could be located on-site within the entity's physical building locations or could be in a virtual setting.*"

Likes 0	
Dislikes 0	

Response

Jessica Meisel-Tognacci - NextEra Energy - Florida Power and Light Co. - 1 - SERC

Answer	No
Document Name	

Comment	
NextEra Energy supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Consider removing "intended" so that it reads "and any Data Centers supporting the function of those rooms."	
Likes 0	
Dislikes 0	
Response	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Eddleman - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	
Document Name	
Comment	
Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	

4. Data Center Definition: The SDT developed a definition for Data Center to support a common understanding of the term across the industry. Do you agree with the SDT's approach and the proposed definition? If not please provide your rational and an alternate proposal.

Jessica Meisel-Tognacci - NextEra Energy - Florida Power and Light Co. - 1 - SERC

Answer	No
Document Name	

Comment

NextEra Energy supports EEI's comments.

Likes 0	
Dislikes 0	

Response

Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF

Answer	No
Document Name	

Comment

AES Clean Energy supports Duke Energy's comments and alternate proposal - see below:

"Duke Energy again appreciates the effort to provide clarification, but does not see a compelling need to define data center. If the Standard Drafting Team determines that data center must become a defined term, we recommend that the SDT leverage a more standard framing of this concept instead of leading with "a network" and that "virtual setting" be changed to "virtual environment". We also recommend that the Drafting team coordinate with the Project 2016-02 team if they continue with the proposal of a Data Center definition to ensure that any virtualization impacts are appropriately considered.

Example Data Center definitions:

https://www.cisco.com/c/en/us/solutions/data-center-virtualization/what-is-a-data-center.html

https://www.ibm.com/topics/data-centers

https://www.paloaltonetworks.com/cyberpedia/what-is-a-data-center

CIP-002.5-1a Criterion 2.12:

Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:

2.12. *Each Control Center or backup Control Center, operated by a registered Transmission Operator or owned by a registered Transmission Owner that is not already included in the High Impact Rating (H), above., with an "aggregate weighted value" exceeding 6000 according to the table below, subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the " weight* *value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.*

Exclusion:

Control Centers or backup Control Centers, operated by a registered Transmission Operator or owned by a registered Transmission Owner, with an "aggregate weighted value" between 6000 and 12000 are excluded provided that the BES Transmission system net export, as calculated for all BES Transmission Lines monitored and controlled by the Control Center or backup Control Center, does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The system net export is based on the hourly integrated power flow values over the course of the most recent two-year period.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Ameren supports EEI's comments on this question.

Likes 0	
Dislikes 0	

Response

Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable

Answer	No
Document Name	

Comment

NST opposes the creation of a new Glossary term, as we believe it would create more problems than it solved. The proposed definition (which, we note, appears to have been copied from the web page: https://www.cisco.com/c/en/us/solutions/data-center-virtualization/what-is-a-data-center.html) would be a good addition to a "Distributed Computing 101" tutorial, but it would, in NST's opinion, only create confusion (or add to existing confusion) in the context of the CIP Standards.

Assuming, for the sake of argument, that most industrial control systems found in modern Registered Entity Control Centers are based on the familiar client-server paradigm, one might be inclined to simply state that the data center is the room/building/cloud where the servers are located. This may be a reasonable presumption if they're in a different zip code than the operations room(s) or "in the cloud," but what if they're in the same building, or even the same room (this is, in fact, exactly where they're located at an NST client's backup Control Center)? What if they're in the same Electronic Security Perimeter as the operator workstations, even while being physically located in a different room within the same building?

NST strongly recommends that the SDT carefully consider the potential implications, particularly on Responsible Entities' CIP-012 programs, of formally defining, "Data Center" before proceeding.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 1,3

Answer	No
Document Name	

Comment

Exelon is in support of EEI response to this question.

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 response of the Edison Electric Institute for question #4.

Likes 0	
Dislikes 0	

Response

Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF

Answer	No
Document Name	

Comment

ITC supports the comments submitted by EEI

Likes 0	

Dislikes 0	

Response

Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC

Answer	No
Document Name	

Comment

The SRC believes that the proposed definition provides additional clarity and counters the recent interpretation of the "data center" term that included substations that only generate and transmit data, as a data center but feel that there are a number areas that need adjustment. These are:

1. The portion of the definition that includes "The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers. The site could be located on-site within the entity's physical building locations or could be in a virtual setting" gives examples and is not part of the definition.

2. The first sentence starts with "A network of computing and storage resources." The "routers, switches, firewalls" listed in the second sentence are communication equipment and are not used for computation or storage.

3. "The site could be located on-site within the entity's physical building locations or could be in a virtual setting." Limits a Data Center to these two locations. It is unclear if this language allows for Data Center equipment (non-virtualized) to be located in a physical building owned by another company.

4. The proposed Data Center definition creates too many questions. We suggest a return to the original intent of resources directly supporting BES functions in a Control Center. Perhaps with a different label like "supporting technology" that includes this narrower scope. The term "data center" is a dated concept in a distributed architecture. Today the emphasis is on functions instead of a place (room). This new term could be modeled after the proposed Control Center definition.

Likes 0	
Dislikes 0	

Response

Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CEHE does not agree with the SDT's approach to define "Data Center". As mentioned in the response to question 3, CEHE does not see the need to define "Data Center," as this term is well understood in the industry. Also, CEHE feels that it would be difficult to prove the intent of "any Data Centers intended to support the function of those rooms," as the definition is proposed. With virtualization technology advancing rapidly, the environment proposed as a "Data Center" could reside within a single piece of hardware or divided across a cloud of dynamically orchestrated nodes, rendering the proposed term "Data Center" obsolete.

Likes 0	

Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	
Require clarity on "virtual settings" as it is included in the current version of CIP standards.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
Q3/Q4. SRP agrees with the approach to distinguish between data centers (or parts of data centers) that do and do not support the functions performed within the Control Center. However, in alignment with Duke, SRP does not see the need to define a data center as we don't believe there is ambiguity with what constitutes a data center. Further, the proposed definition of Control Center already clarifies that it is only addressing data centers (or parts of) that support the real-time functions performed within these designated rooms.	

Likes 0	
Dislikes 0	

Response

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

Manitoba Hydro thinks that the definition of a data center should be included in the Control Center definition instead of being a separate term.

Likes 0	
Dislikes 0	

Response

Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters

Answer	No
Document Name	

Comment

We agree with the approach and disagree with the proposed Dater Center definition. Same comments as in question 3.
The proposed defintion could include almost any data types, whether related to BES or not. BCH seeks clarity on the type of data, limited to Real-time data for monitoring and control and requests the type of data and what it is used for needs to be defined very clearly.
BCH also recommends using a clear term instead of virtual setting. Propose to change this to a term like "Virtual Environment" and appropriatly define it.

Likes 0	
Dislikes 0	

Response

Justin Kuehne - AEP - 3,5,6

Answer	No
Document Name	

Comment

AEP supports the intent of the proposed Data Center definition. However, the language regarding the Data Center site being located in a virtual setting is vague and would benefit from having additional clarity on what is meant by “virtual setting”. Additionally, with the Data Center serving a NERC function, AEP recommends including the “secure area” language to ensure protections are applied to those components and to limit the scope of the defined “network”.

Recommended language includes: *“A network of computing and storage resources within a secure area defined by a physical security perimeter that enable the use of…”*

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5,6

Answer	No
Document Name	

Comment

The term data center is well understood in the industry. The proposed changed to the data center definition encompasses a large scope and could hinder future technological advances and controls for both Control Centers and data centers.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	No
Document Name	

Comment

MPC supports comments submitted by ACES.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment	
FirstEnergy believes the Data Center definition offered seems broad. We suggest the following for clarification: Data Center: A network of computing and storage resources **dedicated** to the use of shared applications in the exchange and management of data. The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers. The site could be located on-site within the entity's physical building locations or could be in a virtual setting.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	No
Document Name	
Comment	
The term data center is well understood in the industry. The proposed changed to the data center definition encompasses a large scope and could hinder future technological advances and controls for both Control Centers and data centers. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource agrees with the comments of the NPCC RSC.	
Likes 0	
Dislikes 0	
Response	

Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	

We believe that the proposed definition provides additional clarity and counters the recent interpretation of the "*data center*" term that included substations that only generate and transmit data, as a data center but feel that there are a number areas that need adjustment. These are:

1. The portion of the definition that includes *"The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers. The site could be located on-site within the entity's physical building locations or could be in a virtual setting"* gives examples and is not part of the definition.

2. The first sentence starts with *"A network of computing and storage resources."* The *"routers, switches, firewalls"* listed in the second sentence are communication equipment and are not used for computation or storage.

3. *"The site could be located on-site within the entity's physical building locations or could be in a virtual setting."* Limits a Data Center to these two locations. It is unclear if this language allows for Data Center equipment (non-virtualized) to be located in a physical building owned by another company.

4. The proposed Data Center definition creates too many questions. We suggest a return to the original intent of resources directly supporting BES functions in a Control Center. Perhaps with a different label like "*supporting technology*" that includes this narrower scope. The term "*data center*" is a dated concept in a distributed architecture. Today the emphasis is on functions instead of a place (room). This new term could be modeled after the proposed Control Center definition.

Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

OPG agrees with the NPCC/RSC's comments.

Likes 0	
Dislikes 0	
Response	

Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	No

Document Name	

Comment

SPP appreciates the SDT's proposed Data Center definition. The current draft would be much stronger without the final sentence due to the ambiguity it creates for cloud services and virtualization, which the previous sentences address without being explicitly stated. SPP proposes the following changes to the proposed Data Center definition:

A network of computing and storage resources that enable the use of shared applications in the exchange and management of data. The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers.

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 defining Data Centers because this term is well understood, sufficiently defined.

Likes 0	
Dislikes 0	

Response

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Cleco agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5

Answer	No
Document Name	
Comment	

We believe that the proposed definition provides additional clarity and counters the recent interpretation of the "data center" term that included substations that only generate and transmit data, as a data center but feel that there are a number areas that need adjustment. These are:

1. The portion of the definition that includes "The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers. The site could be located on-site within the entity's physical building locations or could be in a virtual setting" gives examples and is not part of the definition.

2. The first sentence starts with "A network of computing and storage resources." The "routers, switches, firewalls" listed in the second sentence are communication equipment and are not used for computation or storage.

3. "The site could be located on-site within the entity's physical building locations or could be in a virtual setting." Limits a Data Center to these two locations. It is unclear if this language allows for Data Center equipment (non-virtualized) to be located in a physical building owned by another company.

4. The proposed Data Center definition creates too many questions. We suggest a return to the original intent of resources directly supporting BES functions in a Control Center. Perhaps with a different label like "supporting technology" that includes this narrower scope. The term "data center" is a dated concept in a distributed architecture. Today the emphasis is on functions instead of a place (room). This new term could be modeled after the proposed Control Center definition.

CIP-002.5-1a Criterion 2.12:

Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:

2.12. *Each Control Center or backup Control Center, operated by a registered Transmission Operator or owned by a registered Transmission Owner, that is not already included in the High Impact Rating (H), above., with an "aggregate weighted value" exceeding 6000 according to the table below, subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the " weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.*

Characteristics of a Line

Weight Value

per Characteristic

Each BES Transmission Line less than 100kV

100

Each BES Transmission Line 100kV to 199kV

250

Each BES Transmission Line 200kV to 299kV

700

Each BES Transmission Line 300kV to 499kV

1300

Each BES Transmission Line 500kV and above

0

Each BES Transmission Line identified as part of a Cranking Path

12000

Exclusion:

Control Centers or backup Control Centers, operated by a registered Transmission Operator or owned by a registered Transmission Owner, with an "aggregate weighted value" between 6000 and 12000 are excluded provided that the BES Transmission system net export, as calculated for all BES Transmission Lines monitored and controlled by the Control Center or backup Control Center, does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The system net export is based on the hourly integrated power flow values over the course of the most recent two-year period.

Likes 0	
Dislikes 0	

Response

Byron Booker - Oncor Electric Delivery - 1

Answer	No
Document Name	

Comment

Oncor supports the comments submitted by EEI.

Likes 0	
Dislikes 0	

Response

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3

Answer	No
Document Name	

Comment

BHE does not think a definition is warranted.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	No
Document Name	
Comment	
Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	No
Document Name	
Comment	
Data center is already commonly understood and does not require an industry specific definition.	
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 comments of EEI.	

Likes 0	
Dislikes 0	

Response

Martin Sidor - NRG - NRG Energy, Inc. - 5,6

Answer	No
Document Name	

Comment

No. The Data Center definition is extremely broad. The definition should include a reference to BES Cyber System and the location being different than where the BES Cyber System is operated. Some of these attributes are captured in the definition of Control Center but not here.

Likes 0	
Dislikes 0	

Response

Matt Lewis - Lower Colorado River Authority - 1,5

Answer	No
Document Name	

Comment

The words “virtual setting” are open to interpretation. Could this ‘Data Center” be in the cloud. The definition would allow that.

Likes 0	
Dislikes 0	

Response

Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC

Answer	No
Document Name	

Comment

BHE does not think a definition is warranted.

Likes 0	
Dislikes 0	

Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy again appreciates the effort to provide clarification, but does not see a compelling need to define data center. If the Standard Drafting Team determines that data center must become a defined term, we recommend that the SDT leverage a more standard framing of this concept instead of leading with “a network” and that “virtual setting” be changed to “virtual environment”. We also recommend that the Drafting team coordinate with the Project 2016-02 team if they continue with the proposal of a Data Center definition to ensure that any virtualization impacts are appropriately considered.

Example Data Center definitions:

https://www.cisco.com/c/en/us/solutions/data-center-virtualization/what-is-a-data-center.html

https://www.ibm.com/topics/data-centers

https://www.paloaltonetworks.com/cyberpedia/what-is-a-data-center

Likes 1	Jennie Wike, N/A, Wike Jennie
Dislikes 0	
Response	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	

Sunflower believes there is no need of a definition of data center. If the SDT believes there is, then the phrase “could be in a virtual setting” is not clear.

Likes 1	Jennie Wike, N/A, Wike Jennie
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	

ACES believes there is ambiguity in the phrase "or could be in a virtual setting." Cloud computing is a virtual setting, and this phrasing could allow an entity to move BES Cyber Systems (BCS) to the cloud. ACES does not believe this is the SDT's intent; however, if that is the intent, ACES agrees with the proposed revision. If this is not the SDT's intent, ACES suggests changing the proposed language to "The site could be located on premise within the entity's physical building locations or at a remote location" to avoid any potential misunderstanding by eliminating "in a virtual setting."

Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	

The definition of Data Center would include current non-CIP data centers under its umbrella. The way this project is setting up a hierarchy of terms, Data Centers would only be implicated in CIP compliance when the term Control Center was used in a standard. Vigilance would need to be maintained to ensure that no future standard referenced just the Data Center term, because doing so would place CIP requirements on data centers not related to Control Centers. BPA believes it would be preferable to develop definitions that do not leave the industry open to such occurrences in the future. For example, the definition of Data Center could include "For the purpose of defining a Control Center under the NERC CIP standards, a Data Center is…"

Likes 0	
Dislikes 0	
Response	

Tony Eddleman - Nebraska Public Power District - 1,3,5

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Lyons - Central Iowa Power Cooperative - 1	
Answer	
Document Name	
Comment	
As also stated in comments submitted by ACES, CIPCO believes there is ambiguity in the phrase “or could be in a virtual setting.” Cloud computing is a virtual setting, and this phrasing could allow an entity to move BES Cyber Systems (BCS) to the cloud. CIPCO does not believe this is the SDT’s intent; however, if that is the intent, CIPCO agrees with the proposed revision. If this is not the SDT’s intent, CIPCO suggests changing the proposed language to “The site could be located on premise within the entity’s physical building locations or at a remote location” to avoid any potential misunderstanding by eliminating “in a virtual setting.”	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	
Document Name	
Comment	
Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	

5. Criterion 2.12: The BOT withdrew the previously proposed Reliability Standard CIP-002-6 in February 2021 and issued a resolution stating "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers to safeguard reliability, for the purpose of recommending further action to the Board". Pursuant to further study performed by the SDT via a Field Test, the SDT has determined that the previously proposed bright line of 6000 remains an appropriate initial criterion to differentiate between low impact and medium impact BES Cyber Systems, while safeguarding reliability. Further, the SDT recommends consideration of additional characteristics that may merit inclusion or exclusion. As such, the SDT has recommended revisions based on the previously proposed version of the standard. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters	
Answer	No
Document Name	
Comment	
Given that the transmission line less than 100KV doesn't meet BES definition and is not a BES transmission line, BCH seeks clarity why does SDT try to include non-BES transmission lines as one of the weight factors. Recommendation: Transmission line less than 100KV should be removed from the above table or explain and calrify with some use examples.	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	No
Document Name	
Comment	
It would appear the intent of the updated language under Criterion 2.12 is to exclude Transmission Operator or Transmission Owners entities Control Centers that if compromised do not pose an adverse impact to the BES. The SDT is identifying these less impactful entities by creating the aggregated weighted value table. On top of the table there is an exclusion. This appears to be a convoluted means to determining if a Contol Center should be classified as Low or Medium Impact. A more straightforward method would be that all Control Centers that meet Criterion 1 are High Impact unless they meet the exclusion clause presented above, in which case they would be Medium Impact.	
Likes 0	
Dislikes 0	
Response	

Jessica Meisel-Tognacci - NextEra Energy - Florida Power and Light Co. - 1 - SERC	
Answer	No
Document Name	
Comment	
NextEra Energy is requesting additional information and technical rationale regarding the reliability criteria used to support the values in the table being applied to control centers.	
Likes 0	
Dislikes 0	
Response	

Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy has not identified any issues with this proposal.	
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 comments of EEI.	
Likes 0	
Dislikes 0	
Response	

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes

Document Name	
Comment	
Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Byron Booker - Oncor Electric Delivery - 1	
Answer	Yes
Document Name	
Comment	
Oncor agress with the SDT's approach.	
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 this change.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

FirstEnergy does not oppose the change.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	
Exelon is in support of EEI response to this question.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	

Ameren supports EEI's comments on this question.

Likes 0	
Dislikes 0	

Response

Stacy Engelmann - City of College Station - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Deanna Carlson - Cowlitz County PUD - 3,4,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Paul Mehlhaff - Sunflower Electric Power Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Casey Jones - Berkshire Hathaway - NV Energy - 5 - 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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5	
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	
Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Justin Kuehne - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	

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	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Lyons - Central Iowa Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
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	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC	
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	
Tony Eddleman - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	
Document Name	
Comment	
The scope of this question is not applicable to SPP, so SPP defers to feedback offered from other Responsible Entities who are in scope for this question.	
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

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO

Answer	
Document Name	
Comment	

Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	
Response	

Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable

Answer	
Document Name	

Comment
NST has no comment on this question, as it concerns technical issues that generally fall outside of our portfolio of consulting services.

Likes 0	
Dislikes 0	

Response

6. Criterion 2.12: The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". The intent of this addition was to align the language in the Medium Impact Rating section of CIP-002 Attachment 1 that applies to Control Centers with the language in the High Impact Rating section of CIP-002 Attachment 1. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	
Since there is already a preface with"Each BES Cyber System, …..,associated with any of the following" at the beginning of section 2, this addition is not necessary. Alternatively, use the same wordings in prefaces for all 3 sections.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource agrees with the comments of the NPCC RSC.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	
The language "E*ach BES Cyber System, not included in Section 1 above, associated with any of the following*:" is included at the top of the Medium Impact (Section 2) criteria and applies to all Section 2 criteria. Does the addition of this language mean at the BES Cyber System must be "*used by, located at and associated with?*" Suggest changing the language at the beginning of each of the three sections to use either "*associated with*" or "*used by and located at.*" Having both of these terms apply to three, and only three of the criteria could be interpreted to mean that the SDT is trying to either	

include, or exclude certain BES Cyber Systems for those criteria.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG agrees with the NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	
The language “Each BES Cyber System, not included in Section 1 above, associated with any of the following:” is included at the top of the Medium Impact (Section 2) criteria and applies to all Section 2 criteria. Does the addition of this language mean at the BES Cyber System must be “used by, located at and associated with?” Suggest changing the language at the beginning of each of the three sections to use either “associated with“ or “used by and located at.” Having both of these terms apply to three, and only three of the criteria could be interpreted to mean that the SDT is trying to either include, or exclude certain BES Cyber Systems for those criteria.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	

Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	
Exelon is in support of EEI response to this question.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	

No concerns at this time.

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 change to Criteria 2.11, 2.12 and 2.13.

Likes 0	
Dislikes 0	
Response	
Byron Booker - Oncor Electric Delivery - 1	
Answer	Yes
Document Name	
Comment	

Oncor agress with the SDT's approach.

Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Xcel Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response

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

Comment

Southern Company supports the comments of EEI.

Likes 0	
Dislikes 0	

Response

Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	Yes
Document Name	

Comment

Duke Energy has not identified any issues with this proposal.

Likes 0	
Dislikes 0	

Response

Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Eddleman - Nebraska Public Power District - 1,3,5	
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	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC	
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	
John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Lyons - Central Iowa Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Justin Kuehne - AEP - 3,5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
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	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	
Document Name	

Comment	
Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation has no additional comments Alison Mackellar on behalf of Constellation Segments 5 and 6	
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	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	

Answer	
Document Name	
Comment	
The scope of this question is not applicable to SPP, so SPP defers to feedback offered from other Responsible Entities who are in scope for this question.	
Likes 0	
Dislikes 0	
Response	

7. Criterion 2.12: The SDT proposes to remove the following language "used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines" in favor of explicitly identifying Control Centers that are "operated by a registered Transmission Operator or owned by a registered Transmission Owner". This eliminates the ambiguity that has been identified regarding the application of 'performing the reliability tasks of a Transmission Operator' to Transmission Owners and also eliminates duplication with language that already exists in the NERC defined term Control Center. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5

Answer	No
Document Name	

Comment

While we agree with the removal of this term, however, we feel that the question is misleading since it correctly states that this language is in the Control Center definition but does not state that the language related to "reliability tasks" has also been removed from the proposed Control Center definition.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG agrees with the NPCC/RSC's comments.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5

Answer	No
Document Name	

Comment

While we agree with the removal of this term, however, we feel that the question is misleading since it correctly states that this language is in the Control Center definition but does not state that the language related to "reliability tasks" has also been removed from the proposed Control Center

definition.

Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource agrees with the comments of the NPCC RSC.	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters	
Answer	No
Document Name	
Comment	
The SDT should consider not removing 'reliability-related tasks' from defined terms as this further clarifies who are 'operating personnel'	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy has not identified any issues with this proposal.	
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 comments of EEI.

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	

Comment

Xcel Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response

Byron Booker - Oncor Electric Delivery - 1

Answer	Yes
Document Name	

Comment

Oncor agress with the SDT's approach.

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 changes.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
No concerns at this time.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	
Exelon is in support of EEI response to this question.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	

Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Deanna Carlson - Cowlitz County PUD - 3,4,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - 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	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Justin Kuehne - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
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	

VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Lyons - Central Iowa Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
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	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
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	
Tony Eddleman - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	
Document Name	
Comment	
The scope of this question is not applicable to SPP, so SPP defers to feedback offered from other Responsible Entities who are in scope for this question.	
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

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO

Answer	
Document Name	

Comment

Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	

Response

8. Criterion 2.12: The SDT assigned a 'weight value per characteristic' to BES Transmission Lines less than 100kV given that the NERC defined term Bulk Electric System allows for specific inclusions of equipment that is less than 100kV. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

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

ACES does not agree with including BES Tranismission lines in the weighting scale. The field test report produced by this project did not suggest that they should be included, nor were they part of the field test.

Likes 0	
Dislikes 0	

Response

John Daho - MEAG Power - 1,3 - SERC

Answer	No
Document Name	

Comment

The weighted values should correspond to the risk profile and probability and are not necessary for Transmission Lines less than 100 KV since these lines would require specific inclusions and would be the exception not the norm for the BES.

Likes 0	
Dislikes 0	

Response

Kevin Lyons - Central Iowa Power Cooperative - 1

Answer	No
Document Name	

Comment

CIPCO does not agree with including BES Transmission lines under 100 kV in the weighting scale. The field test report produced by this project did not suggest that they should be included, nor were they part of the field test. If the SDT believes Transmission lines less than 100 kV must be included in the weight value table, the table should indicate only those lines <100 kV that have been specifically identified and included as BES Transmission.

Likes 0	

Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters	
Answer	No
Document Name	
Comment	
Given that NERC BES inclusions of equipment that is less than 100kV only applies to certain transformers and reactive resources rather than transmission lines, transmission line less than 100KV is not a BES Element. BES transmission line less than 100 KV should be removed from Criterion 12 (See our comments in Q5)	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	No
Document Name	
Comment	
MPC supports comments submitted by ACES.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource agrees with the comments of the NPCC RSC.	
Likes 0	
Dislikes 0	

Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	
Suggest that guidance be given on the result of combining the "BES" and the "Transmission Line" NERC defined terms. While the BES term allows for Transmission lines less than 100kV the "Transmission Lines" sets a lower limit of 69kV. Request clarification for a 69 kV line that meets the Transmission Line definition but not the BES definition. This is not specific to this question and may identify an issue that is not technically possible but there is a gap between the X99 and Y00 "Characteristics of Line" levels. A 199.5kV line is not rated on this table. Request explicit explanation (in the Standard) of the weighted value of zero for "Each BES Transmission Line 500 kV and above." (see Criterion 2.5) We agree with the weighted value. Please correct as needed – we understand that a Control Center with such a Tranmission Line is High Impact.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG agrees with the NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	
Suggest that guidance be given on the result of combining the "BES" and the "Transmission Line" NERC defined terms. While the BES term allows for	

Transmission lines less than 100kV the "Transmission Lines" sets a lower limit of 69kV. Request clarification for a 69 kV line that meets the Transmission Line definition but not the BES definition.

This is not specific to this question and may identify an issue that is not technically possible but there is a gap between the X99 and Y00 "Characteristics of Line" levels. A 199.5kV line is not rated on this table.

Request explicit explanation (in the Standard) of the weighted value of zero for "Each BES Transmission Line 500 kV and above." (see Criterion 2.5) We agree with the weighted value. Please correct as needed – we understand that a Control Center with such a Tranmission Line is High Impact.

Likes 0	
Dislikes 0	
Response	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	

Sunflower agrees with ACES comments "ACES does not agree with including BES Tranismission lines in the weighting scale. The field test report produced by this project did not suggest that they should be included, nor were they part of the field test."

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	

Ameren agrees with this change and EEI's comments, provided the table in section 2.5 stays the same.

Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	Yes

Document Name	
Comment	
Exelon is in support of EEI response to this question.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	
ITC does not believe that there should be a weighted value per line approach to determining Medium vs. Low impact facilities. We do not have concerns with including 69kV in the evaluation but only through the exclusion clause using the 75 MW of total export mentioned above.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes

Document Name	
Comment	
FirstEnergy is not opposed to this change.	
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 “weighted value per characteristic” as an improved approach over the existing criterion.	
Likes 0	
Dislikes 0	
Response	
Byron Booker - Oncor Electric Delivery - 1	
Answer	Yes
Document Name	
Comment	
Oncor agress with the SDT's approach.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy has not identified any issues with this proposal.	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tony Eddleman - Nebraska Public Power District - 1,3,5	
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	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Justin Kuehne - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
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	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	
Answer	
Document Name	
Comment	
NST has no comment on this question, as it concerns technical issues that generally fall outside of our portfolio of consulting services.	
Likes 0	
Dislikes 0	
Response	

Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	
Document Name	
Comment	
Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5,6	
Answer	
Document Name	
Comment	
Constellation has no additional comments Alison Mackellar on behalf of Constellation Segments 5 and 6	
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

Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	
Document Name	
Comment	
The scope of this question is not applicable to SPP, so SPP defers to feedback offered from other Responsible Entities who are in scope for this question.	
Likes 0	
Dislikes 0	
Response	

9. Criterion 2.12: The SDT has incorporated an additional characteristic, each BES Transmission Line identified as part of a Cranking Path, as an inclusion characteristic that would automatically ensure a Control Center is dispositioned above the bright line of 12000. This is based on the low probability, but high impact event where a cyber-compromised Control Center impacts restoration efforts following a widespread blackout. Further, systems and facilities critical to system restoration are specifically called out in the Low Impact Rating section of CIP-002 Attachment 1 which is indicative of reliability impacts. Other characteristics that were considered for inclusion such as Flowgates, IROLs and Remedial Action Schemes were ultimately excluded because the mere presence of these does not constitute a reliability risk to the BES and the ones that do impact reliability have already been addressed under CIP-002 Attachment 1 Criteria 2.6 and 2.9. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Based on the low probability, Sunflower suggests to remove this characteristic from Criterion 2.12.	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	
This inclusion seems to be in opposition to the reason for, and in conflict with the language of Criterion 3.4 which identifies as low impact, "Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements."	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

OPG agrees with the NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	
This inclusion seems to be in opposition to the reason for, and in conflict with the language of Criterion 3.4 which identifies as low impact, "Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements."	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1,3, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource agrees with the comments of the NPCC RSC.	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	No
Document Name	
Comment	
Agree with the importance of control centers during restoration. However, instead of imposing cranking path with weight value, it may be less confusing to have a new requirement where each control centers or backup control center that monitors and controls a cranking path should be classified Medium	

Impact.	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
Answer	No
Document Name	
Comment	
The weighted values should correspond to the risk profile and probablity, and since BES Transmission Lines that are part of a Cranking Path have a low probability for an event as stated above, the weighted value should be much less than the proposed 12000.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
Ameren would like more clarity around the phrase "Each BES Transmission Line identified as part of a Cranking Path.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy has not identified any issues with this proposal.	

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 comments of EEI.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

BPA supports the approach. However, there is a concern that a given utility will opt out or avoid designation of a cranking path so that their control center impact would remain low. This could have a negative impact on System Restoration from blackstart resources.

Likes 0	
Dislikes 0	

Response

Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC

Answer	Yes
Document Name	

Comment

Xcel Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response	
Byron Booker - Oncor Electric Delivery - 1	
Answer	Yes
Document Name	
Comment	
Oncor agress with the SDT's approach.	
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 approach.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy is not opposed to this change.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO

Answer	Yes
Document Name	

Comment

MPC supports comments submitted by ACES.

Likes 0

Dislikes 0

Response

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	

Comment

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE)

supports the comments as submitted by Edison Electric Institute (EEI).

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

ACES only sees one potential issue with the proposed language. Some entities in the past chose to abandon Black Start because of the increased CIP requirements. This could occur with Transmission Owners that are a part of the Cranking Path due to increased compliance risk increasing the reliability risk to the BES.

Likes 0

Dislikes 0

Response

Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	
ITC is in agreement that the the BES Transmission Lines identified as part of the Cranking path would automatically identify the Control Center as a Medium Impact Facility. We believe the criteria for Low Impact identification should be any Control Center below the 75 MW total export criteria. This Cranking Path identification would be the exclusion to that clause, making it medium impact.	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	
Exelon is in support of EEI response to this question.	
Likes 0	
Dislikes 0	
Response	

Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Deanna Carlson - Cowlitz County PUD - 3,4,5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
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	

VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Lyons - Central Iowa Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC	
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	
Tony Eddleman - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	
Document Name	
Comment	
The scope of this question is not applicable to SPP, so SPP defers to feedback offered from other Responsible Entities who are in scope for this question.	
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 Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Justin Kuehne - AEP - 3,5,6	
Answer	
Document Name	
Comment	
AEP chooses to abstain from providing a response.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO	
Answer	
Document Name	
Comment	
Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	

Answer	
Document Name	
Comment	
NST has no comment on this question, as it concerns technical issues that generally fall outside of our portfolio of consulting services.	
Likes 0	
Dislikes 0	
Response	

10. Criterion 2.12: The SDT has developed an exclusion clause that would allow the BES Cyber Assets that are associated with a Control Center or backup Control Center to be classified as Low Impact instead of Medium Impact in the event that the calculated "aggregate weighted value" falls between 6000 and 12000, and the calculated BES Transmission system net export does not exceed 75 MW during non-Energy Emergency Alert conditions over the most recent two-year period. The 12000 cap on the "aggregate weighted value" is based on the equivalent of four stations with Medium impact BES Cyber Systems. The selection of the 75 MW threshold is based on the BES definition inclusion criterion for a generation plant. Energy Emergency Alert conditions were excluded given that an entity may be required to provide assistance, including load shed, to support the system. Do you agree with the SDT's approach and the proposed exclusion clause? If not, please provide your rationale and an alternate proposal.

Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF

Answer	No
Document Name	

Comment

ITC believes that the aggregate weighted value system on top of the exclusion clause makes this evaluation convoluted. It also allows for a Control Centers to control a transmission network with up to 24 lines less than 200kV lines while still being classified as Low Impact.

ITC proposes to use exclusion clause proposed under Criterion 2.12 as the determining factor for if a Control Center is Medium or Low Impact. Any Control Center that exceeds 75 MW during non-Energy Emergency Alert (EEA) conditions. The system net export is based on the hourly integrated power flow values over the course of the most recent two-year period would be classified as Medium Impact.

Likes 0	
Dislikes 0	

Response

Joshua London - Eversource Energy - 1,3, Group Name Eversource

Answer	No
Document Name	

Comment

Eversource agrees with the comments of the NPCC RSC.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1,5

Answer	No

Document Name	
Comment	

The language for the exemption seems to allow for the exclusion of a Controls Center as Medium impact if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines, even if these lines are not tied together within the Transmission system controlled by the Control Center.

Does the “net” in “net export” apply to the net total for all applicable BES Transmission Lines at a single point in time or the net export of each of these lines over the two year period.

The two year period portion of the language makes it unclear how new transmission lines are handled even if it is known that they will increase the “net export” beyond the 75MW threshold.

The SDT should provide clarity on if a change in the “net export” fluctuates around or exceeds for the first time, the 75MW threshold. When is exceeding the threshold an “unplanned change”, allowing for a two year implementation and when is it a “planned change” requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center looses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then looses the exemption, if there are not other medium impact programs in place, do they always get two years to either implement the plan or pray that they gain the exemption before the implementation period is over?

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

OPG agrees with the NPCC/RSC's comments.

Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	

The language for the exemption seems to allow for the exclusion of a Controls Center as Medium impact if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines, even if these lines are not tied together within the Transmission system controlled by the Control Center.

Does the “net” in “net export” apply to the net total for all applicable BES Transmission Lines at a single point in time or the net export of each of these lines over the two year period.

The two year period portion of the language makes it unclear how new transmission lines are handled even if it is known that they will increase the “net export” beyond the 75MW threshold.

The SDT should provide clarity on if a change in the “net export” fluctuates around or exceeds for the first time, the 75MW threshold. When is exceeding the threshold an “unplanned change”, allowing for a two year implementation and when is it a “planned change” requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center looses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then looses the exemption, if there are not other medium impact programs in place, do they always get two years to either implement the plan or pray that they gain the exemption before the implementation period is over?

Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	
Exelon is in support of EEI response to this question.	
Likes 0	
Dislikes 0	
Response	

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy is not opposed to this change.	
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 Exclusion clause.	
Likes 0	
Dislikes 0	
Response	
Byron Booker - Oncor Electric Delivery - 1	

Answer	Yes
Document Name	
Comment	
Oncor agress with the SDT's approach.	
Likes 0	
Dislikes 0	
Response	
Joseph Gatten - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Xcel Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF	
Answer	Yes
Document Name	

Comment	
Duke Energy has not identified any issues with this proposal.	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tony Eddleman - Nebraska Public Power District - 1,3,5	
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	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC) Project 2021-03 CIP-002 TOCC	
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	
John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Lyons - Central Iowa Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Golden - Entergy - Entergy Services, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Robertson - BC Hydro and Power Authority - 1,3,5 - WECC, Group Name BC Hydro Balloters	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Justin Kuehne - AEP - 3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Bender - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jamison Cawley - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Clay Walker - Cleco Corporation - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Joseph Amato - Berkshire Hathaway Energy - MidAmerican Energy Co. - 1,3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
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	
Casey Jones - Berkshire Hathaway - NV Energy - 5 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Deanna Carlson - Cowlitz County PUD - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Network and Security Technologies - 1 - NA - Not Applicable	
Answer	
Document Name	
Comment	
NST has no comment on this question, as it concerns technical issues that generally fall outside of our portfolio of consulting services.	

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1 - MRO

Answer	
Document Name	

Comment

Minnesota Power is in agreement with the comments submitted by Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5,6

Answer	
Document Name	

Comment

Constellation has no additional comments

Alison Mackellar on behalf of Constellation Segments 5 and 6

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	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	
Document Name	
Comment	
The scope of this question is not applicable to SPP, so SPP defers to feedback offered from other Responsible Entities who are in scope for this question.	
Likes 0	
Dislikes 0	
Response	

Comments received from MRO NSRF

1. Control Center Definition: The SDT has proposed modifications to the definition of a Control Center based on ambiguity that surfaced during the Field Test. The crux of the ambiguity related to the existence of a TOCC and authority to control versus capability to control. As such, the SDT proposes to clearly specify that a Transmission Owner with the capability to electronically control Transmission Facilities at two or more locations has a Control Center. Further, the SDT is proposing to replace "to perform the reliability tasks" with specific language related to the capability or authority to control Facilities. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No
   Comments:
   The MRO NSRF would like to request additional clarification on the following "electronically control Transmission Facilities at two or more locations".

2. Control Center Definition: The SDT replaced "One or more facilities hosting operating personnel" with "One or more rooms where a responsible entity hosts operating personnel" to eliminate confusion between the terms 'facility' and NERC-defined 'Facility' that appears later in the definition of a Control Center. Further, the use of the term 'rooms' is intended to clarify that a Control Center may be one or more rooms within a larger building. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☒ Yes
   ☐ No
   Comments:

3. Control Center Definition: The SDT replaced "including their associated data centers" with "and any Data Centers intended to support the function

of those rooms" to reference a recommended new defined term for Data Center and to clarify that an entity may have data centers that do not support the functions performed within the Control Center (e.g., data archival, etc.). Do you agree with the SDT's approach? If not, please provide your rational and an alternate proposal.

☐ Yes
☒ No

Comments:

The MRO NSRF is concerned that the definition does differentiate between bussinees and operational systems causing the potential scope creep with an additional definition of 'data center'.

4. Data Center Definition: The SDT developed a definition for Data Center to support a common understanding of the term across the industry. Do you agree with the SDT's approach and the proposed definition? If not please provide your rational and an alternate proposal.

☒ Yes
☐ No

Comments:

5. Criterion 2.12: The BOT withdrew the previously proposed Reliability Standard CIP-002-6 in February 2021 and issued a resolution stating "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers to safeguard reliability, for the purpose of recommending further action to the Board". Pursuant to further study performed by the SDT via a Field Test, the SDT has determined that the previously proposed bright line of 6000 remains an appropriate initial criterion to differentiate between low impact and medium impact BES Cyber Systems, while safeguarding reliability. Further, the SDT recommends consideration of additional characteristics that may merit inclusion or exclusion. As such, the SDT has recommended revisions based on the previously proposed version of the standard. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

☒ Yes
☐ No

Comments:

6. Criterion 2.12: The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". The intent of this addition was to align the language in the Medium Impact Rating section of CIP-002 Attachment 1 that applies to Control Centers with the language in the High Impact Rating section of CIP-002 Attachment 1. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

☒ Yes
☐ No

Comments:

7. Criterion 2.12: The SDT proposes to remove the following language "used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines" in favor of explicitly identifying Control Centers that are "operated by a registered Transmission Operator or owned by a registered Transmission Owner". This eliminates the ambiguity that has been identified regarding the application of 'performing the reliability tasks of a Transmission Operator' to Transmission Owners and also eliminates duplication with language that already exists in the NERC defined term Control Center. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

☒ Yes
☐ No

Comments:

8. Criterion 2.12: The SDT assigned a 'weight value per characteristic' to BES Transmission Lines less than 100kV given that the NERC defined term

Bulk Electric System allows for specific inclusions of equipment that is less than 100kV. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

☒ Yes
☐ No
Comments:

9. Criterion 2.12: The SDT has incorporated an additional characteristic, each BES Transmission Line identified as part of a Cranking Path, as an inclusion characteristic that would automatically ensure a Control Center is dispositioned above the bright line of 12000. This is based on the low probability, but high impact event where a cyber-compromised Control Center impacts restoration efforts following a widespread blackout. Further, systems and facilities critical to system restoration are specifically called out in the Low Impact Rating section of CIP-002 Attachment 1 which is indicative of reliability impacts. Other characteristics that were considered for inclusion such as Flowgates, IROLs and Remedial Action Schemes were ultimately excluded because the mere presence of these does not constitute a reliability risk to the BES and the ones that do impact reliability have already been addressed under CIP-002 Attachment 1 Criteria 2.6 and 2.9. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☒ Yes
   ☐ No
   Comments:

10. Criterion 2.12: The SDT has developed an exclusion clause that would allow the BES Cyber Assets that are associated with a Control Center or backup Control Center to be classified as Low Impact instead of Medium Impact in the event that the calculated "aggregate weighted value" falls between 6000 and 12000, and the calculated BES Transmission system net export does not exceed 75 MW during non-Energy Emergency Alert conditions over the most recent two-year period. The 12000 cap on the "aggregate weighted value" is based on the equivalent of four stations with Medium impact BES Cyber Systems. The selection of the 75 MW threshold is based on the BES definition inclusion criterion for a generation plant. Energy Emergency Alert conditions were excluded given that an entity may be required to provide assistance, including load shed, to support the system. Do you agree with the SDT's approach and the proposed exclusion clause? If not, please provide your rationale and an alternate proposal.

    ☒ Yes
    ☐ No
    Comments:

Comments received from NPCC

1. Control Center Definition: The SDT has proposed modifications to the definition of a Control Center based on ambiguity that surfaced during the Field Test. The crux of the ambiguity related to the existence of a TOCC and authority to control versus capability to control. As such, the SDT proposes to clearly specify that a Transmission Owner with the capability to electronically control Transmission Facilities at two or more locations has a Control Center. Further, the SDT is proposing to replace "to perform the reliability tasks" with specific language related to the capability or authority to control Facilities. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments:
   We recommend changing from "*having the capability or authority to control Facilities;*" to "*having the capability and authority to control Facilities;*"

   The numbered parts of the Control Center definition adds the phrase "*having the capability or authority to control Facilities;*"

In the example “*NERC certified personnel of a Reliability Coordinator, having the capability or authority to control Facilities;*” due to the “*or,*” the definition of Control Center would follow an employee who has the authority to control facilities, regardless of capability, to whatever room they reside in.

2. Control Center Definition: The SDT replaced “One or more facilities hosting operating personnel” with “One or more rooms where a responsible entity hosts operating personnel” to eliminate confusion between the terms ‘facility’ and NERC-defined ‘Facility’ that appears later in the definition of a Control Center. Further, the use of the term ‘rooms’ is intended to clarify that a Control Center may be one or more rooms within a larger building. Do you agree with the SDT’s approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments:
   We agree that the use of the terms “facilities” and “Facilities” can create uncertainty in the meaning of the definition but believe that the proposed changes are too specific to the architecture of the building and does not provide clarity on what is meant by “hosting”.

   For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

   1) If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers but no one is assigned to that desk, is the engineering office a Control Center? or
   2) If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or
   3) If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or
   4) If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center?
   5) If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a Control Center?

3. Control Center Definition: The SDT replaced “including their associated data centers” with “and any Data Centers intended to support the function of those rooms” to reference a recommended new defined term for Data Center and to clarify that an entity may have data centers that do not support the functions performed within the Control Center (e.g., data archival, etc.). Do you agree with the SDT’s approach? If not, please provide your rational and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments:
   The terms “any” and “intended to support the function” could be interpreted to include data centers that are not owned, operated or controlled by the entity.

   The phrase “the function of those rooms” does not limit the function to only those that impact the BES.

   Below, we recommend a new term instead of Data Center. Consistent with that recommendation, we start proposing an alternative approach here.

4. Data Center Definition: The SDT developed a definition for Data Center to support a common understanding of the term across the industry. Do you agree with the SDT’s approach and the proposed definition? If not please provide your rational and an alternate proposal.

☐ Yes
☒ No

Comments:

We believe that the proposed definition provides additional clarity and counters the recent interpretation of the "*data center*" term that included substations that only generate and transmit data, as a data center but feel that there are a number areas that need adjustment. These are:

1. The portion of the definition that includes *"The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers. The site could be located on-site within the entity's physical building locations or could be in a virtual setting"* gives examples and is not part of the definition.
2. The first sentence starts with *"A network of computing and storage resources."* The *"routers, switches, firewalls"* listed in the second sentence are communication equipment and are not used for computation or storage.
3. *"The site could be located on-site within the entity's physical building locations or could be in a virtual setting."* Limits a Data Center to these two locations. It is unclear if this language allows for Data Center equipment (non-virtualized) to be located in a physical building owned by another company.
4. The proposed Data Center definition creates too many questions. We suggest a return to the original intent of resources directly supporting BES functions in a Control Center. Perhaps with a different label like "*supporting technology*" that includes this narrower scope. The term "*data center*" is a dated concept in a distributed architecture. Today the emphasis is on functions instead of a place (room). This new term could be modeled after the proposed Control Center definition.

5. Criterion 2.12: The BOT withdrew the previously proposed Reliability Standard CIP-002-6 in February 2021 and issued a resolution stating "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers to safeguard reliability, for the purpose of recommending further action to the Board". Pursuant to further study performed by the SDT via a Field Test, the SDT has determined that the previously proposed bright line of 6000 remains an appropriate initial criterion to differentiate between low impact and medium impact BES Cyber Systems, while safeguarding reliability. Further, the SDT recommends consideration of additional characteristics that may merit inclusion or exclusion. As such, the SDT has recommended revisions based on the previously proposed version of the standard. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

☒ Yes
☐ No

Comments:

6. Criterion 2.12: The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". The intent of this addition was to align the language in the Medium Impact Rating section of CIP-002 Attachment 1 that applies to Control Centers with the language in the High Impact Rating section of CIP-002 Attachment 1. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

☐ Yes
☒ No

Comments:

The language "E*ach BES Cyber System, not included in Section 1 above, associated with any of the following*:" is included at the top of the Medium Impact (Section 2) criteria and applies to all Section 2 criteria. Does the addition of this language mean at the BES Cyber System must be "*used by, located at and associated with?*" Suggest changing the language at the beginning of each of the three sections to use either "*associated with*" or "*used by and located at.*" Having both of these terms apply to three, and only three of the criteria could be interpreted to mean that the SDT is trying to either include, or exclude certain BES Cyber Systems for those criteria.

7. Criterion 2.12: The SDT proposes to remove the following language “used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines” in favor of explicitly identifying Control Centers that are “operated by a registered Transmission Operator or owned by a registered Transmission Owner”. This eliminates the ambiguity that has been identified regarding the application of ‘performing the reliability tasks of a Transmission Operator’ to Transmission Owners and also eliminates duplication with language that already exists in the NERC defined term Control Center. Do you agree with the SDT’s approach? If not, please provide your rationale and an alternate proposal.

☐ Yes
☒ No

Comments:
While we agree with the removal of this term, however, we feel that the question is misleading since it correctly states that this language is in the Control Center definition but does not state that the language related to “reliability tasks“ has also been removed from the proposed Control Center definition.

8. Criterion 2.12: The SDT assigned a ‘weight value per characteristic’ to BES Transmission Lines less than 100kV given that the NERC defined term Bulk Electric System allows for specific inclusions of equipment that is less than 100kV. Do you agree with the SDT’s approach? If not, please provide your rationale and an alternate proposal.

☐ Yes
☒ No

Comments:
Suggest that guidance be given on the result of combining the “BES” and the “Transmission Line” NERC defined terms. While the BES term allows for Transmission lines less than 100kV the “Transmission Lines” sets a lower limit of 69kV. Request clarification for a 69 kV line that meets the Transmission Line definition but not the BES definition.

This is not specific to this question and may identify an issue that is not technically possible but there is a gap between the X99 and Y00 “Characteristics of Line” levels. A 199.5kV line is not rated on this table.

Request explicit explanation (in the Standard) of the weighted value of zero for “Each BES Transmission Line 500 kV and above.” (see Criterion 2.5) We agree with the weighted value. Please correct as needed – we understand that a Control Center with such a Tranmission Line is High Impact.

9. Criterion 2.12: The SDT has incorporated an additional characteristic, each BES Transmission Line identified as part of a Cranking Path, as an inclusion characteristic that would automatically ensure a Control Center is dispositioned above the bright line of 12000. This is based on the low probability, but high impact event where a cyber-compromised Control Center impacts restoration efforts following a widespread blackout. Further, systems and facilities critical to system restoration are specifically called out in the Low Impact Rating section of CIP-002 Attachment 1 which is indicative of reliability impacts. Other characteristics that were considered for inclusion such as Flowgates, IROLs and Remedial Action Schemes were ultimately excluded because the mere presence of these does not constitute a reliability risk to the BES and the ones that do impact reliability have already been addressed under CIP-002 Attachment 1 Criteria 2.6 and 2.9. Do you agree with the SDT’s approach? If not, please provide your rationale and an alternate proposal.

☐ Yes
☒ No

Comments:
This inclusion seems to be in opposition to the reason for, and in conflict with the language of Criterion 3.4 which identifies as low impact, “Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.”

10. Criterion 2.12: The SDT has developed an exclusion clause that would allow the BES Cyber Assets that are associated with a Control Center or

backup Control Center to be classified as Low Impact instead of Medium Impact in the event that the calculated "aggregate weighted value" falls between 6000 and 12000, and the calculated BES Transmission system net export does not exceed 75 MW during non-Energy Emergency Alert conditions over the most recent two-year period. The 12000 cap on the "aggregate weighted value" is based on the equivalent of four stations with Medium impact BES Cyber Systems. The selection of the 75 MW threshold is based on the BES definition inclusion criterion for a generation plant. Energy Emergency Alert conditions were excluded given that an entity may be required to provide assistance, including load shed, to support the system. Do you agree with the SDT's approach and the proposed exclusion clause? If not, please provide your rationale and an alternate proposal.

☐ Yes
☒ No

Comments:
The language for the exemption seems to allow for the exclusion of a Controls Center as Medium impact if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines, even if these lines are not tied together within the Transmission system controlled by the Control Center.

Does the "net" in "net export" apply to the net total for all applicable BES Transmission Lines at a single point in time or the net export of each of these lines over the two year period.

The two year period portion of the language makes it unclear how new transmission lines are handled even if it is known that they will increase the "net export" beyond the 75MW threshold.

The SDT should provide clarity on if a change in the "net export" fluctuates around or exceeds for the first time, the 75MW threshold. When is exceeding the threshold an "unplanned change", allowing for a two year implementation and when is it a "planned change" requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center looses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then looses the exemption, if there are not other medium impact programs in place, do they always get two years to either implement the plan or pray that they gain the exemption before the implementation period is over?

Comments received from Tacoma Power

1. <u>Control Center Definition:</u> The SDT has proposed modifications to the definition of a Control Center based on ambiguity that surfaced during the Field Test. The crux of the ambiguity related to the existence of a TOCC and authority to control versus capability to control. As such, the SDT proposes to clearly specify that a Transmission Owner with the capability to electronically control Transmission Facilities at two or more locations has a Control Center. Further, the SDT is proposing to replace "to perform the reliability tasks" with specific language related to the capability or authority to control Facilities. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments:
   Tacoma Power does not agree with changing the existing Control Center definition. Instead, Tacoma Power proposes creating a standalone definition for Transmission Owner Control Center (TOCC), and then a new CIP-002 criterion. Trying to parse out the proposed Control Center definition is a challenge and has far reaching impacts beyond CIP-002. In order to limit the impacts and ensure the definition resolves the concerns in the SAR, Tacoma Power supports a standalone definition and new CIP-002 criterion for TOCC only.

If the SDT wants to continue with this revision, Tacoma Power has several issues with the proposed changes, as described below. Tacoma Power recommends instead of stating "having the capability or authority to control Facilities", the original language of the Control Center definition of "perform real-time reliability tasks" should be used. Controlling Facilities is only a small part of the responsibilities of the NERC certified personnel of a BA or TOP. There are other real-time reliability tasks that are essential functions. Additionally, "real-time reliability tasks" aligns with the language used in PER Standards.

Tacoma Power is also concerned that the term "function" in "to support the function of those rooms" is not clearly defined. An entities' Control Center can also provide non-BES functions and the proposed wording implies that these functions would also include non-BES in the scope.

Tacoma Power disagrees with the first bullet in the definition. Reliability Coordinators do not have the capability or authority to control Facilities, but Reliability Coordinators do perform reliability tasks, as stated in the current definition.

Tacoma Power needs additional information or examples to understand how a Transmission Owner operates Transmission Facilities. Operations are performed by Transmission Operators, as defined in the NERC ROP, Appendix 5b, Section 2 definition of Transmission Operator and Transmission Owner. Implying that a Transmission Owner has operating authority is confusing and conflicts with the ROP functional definitions. Tacoma Power recommends striking "operating" from "operating personnel" in the leading sentence, the fourth and fifth bullet to clarify that a Transmission Owner and Generator Operator do not operate Facilities.

Based on the above comments, Tacoma Power recommends the following Control Center definition changes:

Control Center: One or ***more facilities hosting*** *~~rooms where a responsible entity hosts~~ ~~operating~~ personnel, as detailed below, that monitor and control the Bulk Electric System (BES) in real-time* ***to perform reliability tasks, including their associated Data Centers*****~~:~~***~~, and any Data Centers intended to support the function of those rooms.~~*

1. *NERC certified personnel of a Reliability Coordinator~~,~~ having the capability or authority* ***to perform real-time reliability tasks*** *~~control Facilities~~;*
2. *NERC certified personnel of a Balancing Authority~~,~~ having the capability or authority* ***to perform real-time reliability tasks*** *~~control Facilities~~;*
3. *NERC certified personnel of a Transmission Operator having the capability or authority* ***to*** *control Transmission Facilities at two or more locations,*
4. *Transmission Owner* ***~~operating~~*** *personnel having the capability to electronically control Transmission Facilities at two or more locations; or*
5. *Generation Operator* ***~~operating~~*** *personnel having the capability to electronically control generation Facilities at two or more locations.*

2. Control Center Definition: The SDT replaced "One or more facilities hosting operating personnel" with "One or more rooms where a responsible entity hosts operating personnel" to eliminate confusion between the terms 'facility' and NERC-defined 'Facility' that appears later in the definition of a Control Center. Further, the use of the term 'rooms' is intended to clarify that a Control Center may be one or more rooms within a larger building. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

☐ Yes
☒ No

Comments:
Tacoma Power does not agree that "room" is needed or an improvement to the existing language. For example, a Control Center could be a building. It doesn't matter if a facility has one control room or multiple control rooms – it still falls under the term "facility." Therefore, it's better to stick with the lowercase facility. There is no confusion between Facility and facility. In the O&P Standards, the lowercase and uppercase facility is often used concurrently (see Facility Ratings).

Any change to the Control Center definition should be aligned with adding Control Centers as applicable rooms/facilities under CIP-002 4.2.2.

Currently the standard is only applicable to "All BES Facilities", whereas a Control Room does not meet the NERC definition of Facility.

3. Control Center Definition: The SDT replaced "including their associated data centers" with "and any Data Centers intended to support the function of those rooms" to reference a recommended new defined term for Data Center and to clarify that an entity may have data centers that do not support the functions performed within the Control Center (e.g., data archival, etc.). Do you agree with the SDT's approach? If not, please provide your rational and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments: Tacoma Power does not agree with the change. Tacoma Power recommends keeping the existing Control Center definition term language of "including their associated data centers."

4. Data Center Definition: The SDT developed a definition for Data Center to support a common understanding of the term across the industry. Do you agree with the SDT's approach and the proposed definition? If not please provide your rational and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments:
   Tacoma Power is concerned that the proposed Data Center definition is too broad and may result in unintended scope creep. For example, this definition could encompass corporate business systems, telephony, camera monitoring systems, radios, or energy balance market systems.

   Tacoma Power recommends bounding the Data Center definition to only reliability support functions.

   Tacoma Power recommends the following changes to the Data Center definition that will better define the intended scope:

   Data Center: location housing computing and storage resources that ~~enable the use of~~ ***host*** *shared applications in the exchange and management of data* ***that directly supports Reliable Operation****. ~~The key components of a Data Center may include, but are not limited to, routers, switches, firewalls, storage systems, servers, and application-delivery controllers. The site could be located on-site within the entity's physical building locations or could be in a virtual setting.~~*

   In addition to revising the Data Center definition, Tacoma Power recommends that the CIP-002 redline clearly states that the Responsible Entity would be responsible for defining the Data Center equipment that directly supports Reliable Operation.

   Alternatively, Tacoma Power recommends leaving data center as an undefined term.

5. Criterion 2.12: The BOT withdrew the previously proposed Reliability Standard CIP-002-6 in February 2021 and issued a resolution stating "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers to safeguard reliability, for the purpose of recommending further action to the Board". Pursuant to further study performed by the SDT via a Field Test, the SDT has determined that the previously proposed bright line of 6000 remains an appropriate initial criterion to differentiate between low impact and medium impact BES Cyber Systems, while safeguarding reliability. Further, the SDT recommends consideration of additional characteristics that may merit inclusion or exclusion. As such, the SDT has recommended revisions based on the previously proposed version of the standard. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments:

The proposed language is unclear on how to calculate the weighted value for many sections of Tacoma Power's 115 kV sub-trasmission system. The existing CIP-002-6 supplemental material only address configurations common at 230 kV and it does not have examples of common 115 kV sub-transmission configurations.

The TOCC_Field_Test_Final_Report contains some limited guidance, but that guidance appears to dramatically overestimate the impact of typical 115 kV sub-transmission lines when looped through small distribution stations. For example, we have 5 mile 115 kV line that loops through 3 small distribution stations. If the entire NE-Blair-Lincoln-East F-St Paul line is counted as a single line, it would have a weighted value of 250, whereas if each series section is counted as a separate line, this would have a weighted value of 1000. It would be absurd to weight this short 115 kV line section more heavily that a regional 230 kV line running for dozens of miles.

Additionally, in different poritons of the TOCC_Field_Test_Final_Report there were conflicting recommendations. In one place it suggested the criteria be to use elements that interrupt fault current, whereas another plant suggested the criteria be to use elements that can intterupt network flows. These criteria result in vastly different aggregate weighted values when applied to Tacoma Power's system.

6. Criterion 2.12: The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". The intent of this addition was to align the language in the Medium Impact Rating section of CIP-002 Attachment 1 that applies to Control Centers with the language in the High Impact Rating section of CIP-002 Attachment 1. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☒ Yes
   ☐ No

   Comments:

7. Criterion 2.12: The SDT proposes to remove the following language "used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines" in favor of explicitly identifying Control Centers that are "operated by a registered Transmission Operator or owned by a registered Transmission Owner". This eliminates the ambiguity that has been identified regarding the application of 'performing the reliability tasks of a Transmission Operator' to Transmission Owners and also eliminates duplication with language that already exists in the NERC defined term Control Center. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments:
   Tacoma Power supports keeping the language "used to perform the reliability tasks of a Transmission Operator in real-time to monitor and control BES Transmission Lines".

8. Criterion 2.12: The SDT assigned a 'weight value per characteristic' to BES Transmission Lines less than 100kV given that the NERC defined term Bulk Electric System allows for specific inclusions of equipment that is less than 100kV. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments:
   The original work to develop the 'weight value per characteristic' focused on EHV transmission, so it is not clear why picking a value of 100 is an appropriate value for subtransmission at less than 100 kV. Subtransmission systems tend be configured much differently compared to EHV transmission, and the proposed value is likely to overestimate the importance of subtransmission elements.

9. Criterion 2.12: The SDT has incorporated an additional characteristic, each BES Transmission Line identified as part of a Cranking Path, as an

inclusion characteristic that would automatically ensure a Control Center is dispositioned above the bright line of 12000. This is based on the low probability, but high impact event where a cyber-compromised Control Center impacts restoration efforts following a widespread blackout. Further, systems and facilities critical to system restoration are specifically called out in the Low Impact Rating section of CIP-002 Attachment 1 which is indicative of reliability impacts. Other characteristics that were considered for inclusion such as Flowgates, IROLs and Remedial Action Schemes were ultimately excluded because the mere presence of these does not constitute a reliability risk to the BES and the ones that do impact reliability have already been addressed under CIP-002 Attachment 1 Criteria 2.6 and 2.9. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

☐ Yes
☒ No

Comments:
The inclusion of blackstart units into various NERC standards had the unintended consequence that many blackstart units being converted to normal units by their owners in order to avoid extensive compliance efforts. Inclusions of the Cranking Path may have similar unintended consequences.

10. Criterion 2.12: The SDT has developed an exclusion clause that would allow the BES Cyber Assets that are associated with a Control Center or backup Control Center to be classified as Low Impact instead of Medium Impact in the event that the calculated "aggregate weighted value" falls between 6000 and 12000, and the calculated BES Transmission system net export does not exceed 75 MW during non-Energy Emergency Alert conditions over the most recent two-year period. The 12000 cap on the "aggregate weighted value" is based on the equivalent of four stations with Medium impact BES Cyber Systems. The selection of the 75 MW threshold is based on the BES definition inclusion criterion for a generation plant. Energy Emergency Alert conditions were excluded given that an entity may be required to provide assistance, including load shed, to support the system. Do you agree with the SDT's approach and the proposed exclusion clause? If not, please provide your rationale and an alternate proposal.

☒ Yes
☐ No

Comments:
The proposed value of 12000 seems appropriate as long as the definition of a line does not count individual subtransmission segments between distribution substations. If the proposal is to count every circuit breaker location as forming a separate line, the value of 12000 is much too low.

Comments received from Hydro One Networks, Inc.

1. Control Center Definition: The SDT has proposed modifications to the definition of a Control Center based on ambiguity that surfaced during the Field Test. The crux of the ambiguity related to the existence of a TOCC and authority to control versus capability to control. As such, the SDT proposes to clearly specify that a Transmission Owner with the capability to electronically control Transmission Facilities at two or more locations has a Control Center. Further, the SDT is proposing to replace "to perform the reliability tasks" with specific language related to the capability or authority to control Facilities. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments: Suggest to change "having the capability and authority to control" for 5 points, in order to ensure that the room(s) can only be considered a Control Center when the personnels control with authority. Suggest to retain "to perform the reliability tasks" or define the function (such as BES Reliabilility Operating Services".

2. Control Center Definition: The SDT replaced "One or more facilities hosting operating personnel" with "One or more rooms where a responsible entity hosts operating personnel" to eliminate confusion between the terms 'facility' and NERC-defined 'Facility' that appears later in the

definition of a Control Center. Further, the use of the term 'rooms' is intended to clarify that a Control Center may be one or more rooms within a larger building. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

☒ Yes
☐ No

Comments:

3. <u>Control Center Definition:</u> The SDT replaced "including their associated data centers" with "and any Data Centers intended to support the function of those rooms" to reference a recommended new defined term for Data Center and to clarify that an entity may have data centers that do not support the functions performed within the Control Center (e.g., data archival, etc.). Do you agree with the SDT's approach? If not, please provide your rational and an alternate proposal.

   ☒ Yes
   ☐ No

   Comments: agree with the change, but require clarity on "Data Center"

4. <u>Data Center Definition:</u> The SDT developed a definition for Data Center to support a common understanding of the term across the industry. Do you agree with the SDT's approach and the proposed definition? If not please provide your rational and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments: Require clarity on "virtual settings" as it is not included in the current version of CIP standards. It may open up other concerns on virtualization and cloud computing.

5. <u>Criterion 2.12:</u> The BOT withdrew the previously proposed Reliability Standard CIP-002-6 in February 2021 and issued a resolution stating "that NERC Staff, working with stakeholders, is directed to promptly conduct further study of the need to readdress the applicability of the CIP Reliability Standards to such Control Centers to safeguard reliability, for the purpose of recommending further action to the Board". Pursuant to further study performed by the SDT via a Field Test, the SDT has determined that the previously proposed bright line of 6000 remains an appropriate initial criterion to differentiate between low impact and medium impact BES Cyber Systems, while safeguarding reliability. Further, the SDT recommends consideration of additional characteristics that may merit inclusion or exclusion. As such, the SDT has recommended revisions based on the previously proposed version of the standard. Do you agree with this approach? If not, please provide your rationale and an alternate proposal.

   ☒ Yes
   ☐ No

   Comments:

6. <u>Criterion 2.12:</u> The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". The intent of this addition was to align the language in the Medium Impact Rating section of CIP-002 Attachment 1 that applies to Control Centers with the language in the High Impact Rating section of CIP-002 Attachment 1. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments: Since there is already a preface with"Each BES Cyber System, ...,assoicated with any of the following" at the beginning of section 2, this addition is not necessary. Alternatively, use the same wordings in prefaces for all 3 sections.

7. <u>Criterion 2.12:</u> The SDT proposes to remove the following language "used to perform the reliability tasks of a Transmission Operator in real-time to

monitor and control BES Transmission Lines" in favor of explicitly identifying Control Centers that are "operated by a registered Transmission Operator or owned by a registered Transmission Owner". This eliminates the ambiguity that has been identified regarding the application of 'performing the reliability tasks of a Transmission Operator' to Transmission Owners and also eliminates duplication with language that already exists in the NERC defined term Control Center. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

☒ Yes
☐ No

Comments:

8. Criterion 2.12: The SDT assigned a 'weight value per characteristic' to BES Transmission Lines less than 100kV given that the NERC defined term Bulk Electric System allows for specific inclusions of equipment that is less than 100kV. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☒ Yes
   ☐ No

   Comments:

9. Criterion 2.12: The SDT has incorporated an additional characteristic, each BES Transmission Line identified as part of a Cranking Path, as an inclusion characteristic that would automatically ensure a Control Center is dispositioned above the bright line of 12000. This is based on the low probability, but high impact event where a cyber-compromised Control Center impacts restoration efforts following a widespread blackout. Further, systems and facilities critical to system restoration are specifically called out in the Low Impact Rating section of CIP-002 Attachment 1 which is indicative of reliability impacts. Other characteristics that were considered for inclusion such as Flowgates, IROLs and Remedial Action Schemes were ultimately excluded because the mere presence of these does not constitute a reliability risk to the BES and the ones that do impact reliability have already been addressed under CIP-002 Attachment 1 Criteria 2.6 and 2.9. Do you agree with the SDT's approach? If not, please provide your rationale and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments: Agree with the importance of control centers during restoration. However, instead of imposing cranking path with weight value, it may be less confusing to have a new requirement where each control centers or backup control center that monitors and controls a cranking path should be classified Medium Impact.

10. Criterion 2.12: The SDT has developed an exclusion clause that would allow the BES Cyber Assets that are associated with a Control Center or backup Control Center to be classified as Low Impact instead of Medium Impact in the event that the calculated "aggregate weighted value" falls between 6000 and 12000, and the calculated BES Transmission system net export does not exceed 75 MW during non-Energy Emergency Alert conditions over the most recent two-year period. The 12000 cap on the "aggregate weighted value" is based on the equivalent of four stations with Medium impact BES Cyber Systems. The selection of the 75 MW threshold is based on the BES definition inclusion criterion for a generation plant. Energy Emergency Alert conditions were excluded given that an entity may be required to provide assistance, including load shed, to support the system. Do you agree with the SDT's approach and the proposed exclusion clause? If not, please provide your rationale and an alternate proposal.

    ☒ Yes
    ☐ No

    Comments:

Standard Authorization Request (SAR)

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

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

<table>
<tr><th colspan="4">Requested information</th></tr>
<tr><td>SAR Title:</td><td colspan="3">CIP-002-5.1a Criterion 1.3 Revision</td></tr>
<tr><td>Date Submitted:</td><td colspan="3">March 20, 2023</td></tr>
<tr><td colspan="4">SAR Requester</td></tr>
<tr><td>Name:</td><td colspan="3">Mark Atkins, [member of 2021-03 CIP-002 Transmission Owner Control Center (TOCC)]</td></tr>
<tr><td>Organization:</td><td colspan="3">AESI-Inc.</td></tr>
<tr><td>Telephone:</td><td>770.870.1630 ext. 277</td><td>Email:</td><td>marka@aesi-inc.com</td></tr>
<tr><td colspan="4">SAR Type (Check as many as apply)</td></tr>
<tr><td colspan="2">☐ New Standard
☒ Revision to Existing Standard
☐ Add, Modify, or Retire a Glossary Term
☐ Withdraw/retire an Existing Standard</td><td colspan="2">☐ Imminent Action/ Confidential Issue (SPM Section 10)
☐ Variance development or revision
☐ Other (Please specify)</td></tr>
<tr><td colspan="4">Justification for this proposed standard development project (Check all that apply to help NERC prioritize development)</td></tr>
<tr><td colspan="2">☐ Regulatory Initiation
☐ Emerging Risk (Reliability Issues Steering Committee) Identified
☐ Reliability Standard Development Plan</td><td colspan="2">☐ NERC Standing Committee Identified
☐ Enhanced Periodic Review Initiated
☒ Industry Stakeholder Identified</td></tr>
<tr><td colspan="4">Industry Need (What Bulk Electric System (BES) reliability benefit does the proposed project provide?):</td></tr>
<tr><td colspan="4">NERC Reliability Standard CIP-002-5.1a requires entities to identify and categorize Bulk Electric System (BES) Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

Criterion 1.3 needs to have Criterion 2.6[1] reinserted into Criterion 1.3 for the Transmission Operator (TOP) to ensure proper high-impact categorization of BES Cyber System(s) related to Transmission assets that are identified as critical to the derivation of Interconnection Reliability Operating Limits</td></tr>
</table>

[1] Criterion 2.6 reads: "Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

Requested information
(IROLs) and their associated contingencies as also required of the Balancing Authority (BA) in Criterion 1.2 and the Generator Operator (GOP) in Criterion 1.4.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
The proposed project will require the TOP to categorize its BES Cyber System(s) as high impact that meet Criterion 2.6 as is also required of the BA and GOP in Criterion 1.2 and 1.4, respectively. By including Criterion 2.6 in Criterion 1.3, the TOP's BES Cyber Systems(s) will be properly categorized as high impact for Transmission Facilities at a single station or substation location that is identified as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."
Project Scope (Define the parameters of the proposed project):
1. Confirm consensus that Criterion 2.6 is applicable for identifying BES Cyber System(s) as a high impact in "[e]ach Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet Criterion 2.6. 2. In CIP-002-5.1a Attachment 1, add Criterion 2.6 to the list of Criteria in Criterion 1.3. 3. Conduct a review of NERC Reliability Standard CIP-002-5.1a and other associated NERC documents concerning Criterion 2.6 to ensure that the inclusion of Criterion 2.6 within Criterion 1.3 is in alignment with any other associated documents.
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[2] that 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 the development of the Standard or definition):
DELIVERABLES 1. The addition of Criterion 2.6 in the list of criteria found in Criterion 1.3 of CIP-00-5.1a Attachment 1. 2. Initiate or complete necessary revisions to associated documents related to the inclusion of Criterion 2.6 in Criterion 1.3. **BACKGROUND** CIP-002-5.1a Attachment 1, **Criterion 1.2** identifies BES Cyber System(s) as a high impact in "[e]ach Control Center or backup Control Center used to perform the functional obligations of the **Balancing Authority**: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, **2.6**, or 2.9." The assets that meet each of the criterion as referenced in criterion 1.2 meet the medium impact rating level for a generation or Transmission Facility.

[2] 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
CIP-002-5.1a Attachment 1, **Criterion 1.4** identifies BES Cyber System(s) as a high impact in "[e]ach <u>Control Center or backup Control Center</u> used to perform the functional obligations of the **Generator Operator** for one or more of the assets that meet criterion 2.1, 2.3, **2.6**, or 2.9." The assets that meet each of the criterion as referenced in criterion 1.4 meet the medium impact rating level for a generation Facility. CIP-002-5.1a Attachment 1, **Criterion 1.3** identifies BES Cyber System(s) as a high impact in "[e]ach <u>Control Center or backup Control Center</u> used to perform the functional obligations of the **Transmission Operator** for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10." This is not consistent with Criterion 1.2 for the BA or Criterion 1.4 for the GOP. Criterion 2.6 is omitted from Criterion 1.3. The issue is that Criterion 2.6 is included in Criteria 1.2 and 1.4 for the BA and GOP, respectively, but not in Criterion 1.3 for the TOP. When BA, TOP, and GOP all categorize BES Cyber System(s) as high for those assets meeting Criterion 2.6, the application of cyber security requirements is commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems. The archived Project 2008-06 Cyber Security Order 706 Version 5 CIP Standards[3] is the project where CIP-002-4 was revised to version 5. Draft 1 of version 5, included Criterion 2.6 as a criterion (formerly 2.8) for categorizing BES Cyber System(s) used by the TOP concerning IROLs. Through the development process, the criterion was remapped from 2.8 to 2.6 in draft 2.[4] Also, in draft 2, the development team removed what became Criterion 2.6 concerning IROLs from Criterion 1.3 that identified BES Cyber System(s) as a high impact in "[e]ach <u>Control Center or backup Control Center</u> used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10." A technical justification is not necessary since it appears the omission of Criterion 2.6 in Criterion 1.3 was an error created during the revision of CIP-002 from version 4 to 5 when ordering the medium impact criteria.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
The cost impact is unknown at this time. However, a question will be asked during the comment period to ensure cost aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):

[3] https://www.nerc.com/pa/Stand/Pages/Project_2008-06_Cyber_Security_Version_5_CIP_Standards.aspx
[4] In transition from the version 5 revision work between drafts 1 and 2, the Transmission Owner (TO) was removed from Criterion 2.8 (draft1) and the criterion became Criterion 2.6 (draft 2) through to the final version 5 of the standard.

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):
Balancing Authority, Distribution Provider, Generator Operator, Generator Owner, Interchange Coordinator or Interchange Authority, Reliability Coordinator, Transmission Operator, Transmission Owner
Do you know of any consensus building activities[5] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
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)?
2021-03 CIP-002 Transmission Owner Control Center (TOCC) The 2021-03 CIP-002 Transmission Owner Control Center (TOCC) is currently reviewing and developing revised language for criterion 2.12. In those discussions, the question regarding criterion 2.6 and criterion 1.3 has been raised, but the justification for criteria 2.6 being omitted from criterion 1.3 is unknown.
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.

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 an 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, and 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.

[5] 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	
☒	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 from 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 a Guidance document

Version History

Version	Date	Owner	Change Tracking
1	June 3, 2013		Revised
1	August 29, 2014	Standards Information Staff	Updated template
2	January 18, 2017	Standards Information Staff	Revised
2	June 28, 2017	Standards Information Staff	Updated template

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

Unofficial Comment Form

Project 2021-03 CIP-002

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on the **Project 2021-03 Standard Authorization Request (SAR) by 8 p.m. Eastern, Friday, August 18, 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

The purpose of Reliability Standard CIP-002-5.1a is "[to] identify and categorize Bulk Electric System (BES) Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES."

Criterion 1.3 needs to have Criterion 2.6[1] reinserted into the Transmission Operator (TOP) to ensure proper high impact categorization of BES Cyber System(s) related to Transmission assets that are identified as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies as also required of the Balancing Authority (BA) in Criterion 1.2 and the Generator Operator (GOP) in Criterion 1.4.

The proposed project will require the TOP to categorize its BES Cyber Systems as high impact that meet Criterion 2.6 as is also required of the BA and GOP in Criterion 1.2 and 1.4, respectively. By including Criterion 2.6 in Criterion 1.3, the TOP's BES Cyber Systems will be properly categorized as high impact for transmission facilities at a single station or substation location that is identified "as critical to the derivation of IROLs and their associated contingencies."

[1] Criterion 2.6 reads: "Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies."

Questions

1. Do you agree with the proposed scope as described in the SAR? 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 Standard drafting team to consider, if desired.

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2021-03 CIP-002
Standard Authorization Request

Formal Comment Period Open through August 18, 2023

Now Available

A 30-day formal comment period for the **CIP-002-5.1a Criterion 1.3 Revision Standard Authorization Request (SAR)**, is open through **8 p.m. Eastern, Friday, August 18, 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 2021-02 CIP-002 observer list" in the Description Box.

Comment Report

Project Name:	2021-03 CIP-002 | CIP-002-5.1a Criterion 1.3 Revision Standard Authorization Request
Comment Period Start Date:	7/20/2023
Comment Period End Date:	8/18/2023
Associated Ballots:	

There were 35 sets of responses, including comments from approximately 105 different people from approximately 89 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 SAR? 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 Standard 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
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
					Colette Caudill	East Kentucky Power Cooperative	1,3	SERC
					Jason Procuniar	Buckeye Power, Inc.	4	RF
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO

					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
California ISO	Monika Montez	2	WECC	ISO/RTO Council Standards Review Committee (SRC)	Monika Montez	CAISO	2	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kathleen Goodman	ISO-NE	2	NPCC
					Gregory Campoli	New York Independent	2	NPCC

						System Operator		
					Helen Lainis	IESO	2	NPCC
					Elizabeth Davis	PJM	2	RF
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC

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

					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
Western Electricity Coordinating Council	Steven Rueckert	10		WECC CIP	Steve Rueckert	WECC	10	WECC
					Morgan King	WECC	10	WECC
					Deb McEndaffer	WECC	10	WECC
					Tom Williams	WECC	10	WECC

1. Do you agree with the proposed scope as described in the SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope, please provide your recommendation and explanation.	
Jonathan Robbins - AES - AES Corporation - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
While AES Clean Energy is not registered as a TOP, it agrees with the proposed scope as it provides clarity and consistency with existing criterion for BAs (Criterion 1.2) and GOPs (Criterion 1.4).	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	Yes
Document Name	
Comment	
MPC supports the comments submitted by the MRO NERC Standards Review Forum (NSRF).	
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 proposed scope described in the SAR.	
Likes 0	
Dislikes 0	

Response

Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	

The MRO NSRF agrees that the scope is appropriate to achieve the stated purpose.

However, the MRO NSRF notes a disconnect between the three items of the project scope and the two deliverables. We suggest re-numbering Deliverables 1 and 2 to 2 and 3 to correspond with the Project Scope and insert a new Deliverable 1 to determine if Criterion 2.6 was deliberately removed from Criterion 1.3 in draft 2 of CIP-002-5, or if there exists current justification for maintaining the omission.

As currently written, the SAR is directing implementation of Project Scope items 2 and 3 without first satisfying item 1. Project 2021-03 should first determine whether Criterion 2.6 should only require medium impact for TOP Control Centers given no cited impact to the reliability of the BES over the last 7 years.

The MRO NSRF is concerned that a TOP operating a medium impact Control Center may have to elevate the Control Center's categorization to high impact based on a transient Transmission Substation IROL declaration that could take place any given year but, due to changes in grid topology, be rescinded the following year.

The MRO NSRF understands that Project 2021-03 is currently revising Criterion 2.6 under task 2 to address this issue by adding a qualifier to IROLs limiting the Criterion to those "expected to last 36 months or longer from the date of RC provision of notice." We urge that these efforts be coordinated to address both issues simultaneously.

Likes 0	
Dislikes 0	

Response

Alan Kloster - 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) for question 1.

Likes 0	
Dislikes 0	

Response

Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC (CEHE) supports the comments as submitted by the Edison Electric Institute (EEI).

Likes 0	

Dislikes 0	

Response

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	

Comment

Southern Indiana Gas and Electric (SIGE) supports the comments as submitted by the Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	

Response

Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF

Answer	Yes
Document Name	

Comment

Duke Energy agrees with the scope, and supports EEI comments.

Likes 0	
Dislikes 0	

Response

Kent Feliks - AEP - 3,5,6

Answer	Yes
Document Name	

Comment

On behalf of AEP Service Corp. Segments 1,3,5,6.

The scope of the SAR appears to be sufficiently limited to address this signular issue/omission.

Likes 0	
Dislikes 0	

Response	
Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Recommend this revision is incorporated into a larger CIP-002 standard revision project. Please consider updating implementation timelines and impact if there is a responsible entity that changes from a lower impact to a higher impact scope. The implementation plan should start 24 calendar months from the entities first CIP-002 R2 review post the effective date.	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Cleco Corporation - Cleco Power - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Cleco agrees with comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Recommend this revision is incorporated into a larger CIP-002 standard revision project. Please consider updating implementation timelines and impact if there is a responsible entity that changes from a lower impact to a higher impact scope. The implementation plan should start 24 calendar months from the entities first CIP-002 R2 review post the effective date.	

Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 1,3	
Answer	Yes
Document Name	
Comment	
Exelon is aligning with EEI in response to this question.	
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 Comapny agrees with the comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
While EEI does not oppose the intended objectives of this SAR, we ask that the SDT ensure coordination between this SAR and the SAR identified as “Modifications to CIP-002 and CIP-014. We further ask that before Criterion 2.6 becomes an enforceable part of Criterion 1.3, that issues surrounding	

short term IROL declarations be resolved in order to avoid negatively impacting Control Center or backup Control Center, used to perform the functional obligations of the Transmission Operator, that currently have an impact rating of medium impact.

Industry Need (Section) – *EEI asks that the word reinsert be changed to insert because Criterion 2.6 was never an approved or enforceable part of Criterion 1.3. While the first draft of CIP-002-5 did include Criterion 2.6 (identified as 2.8 in Draft 1) it was subsequently removed from Criterion 1.3 but added to Criterion 1.2 and 1.4, reflecting SDT intentionality. While it is clear this was intentional, noting 2.6 was purposely added to 1.2 and 1.4 during the development of draft 2, we have been unable to validate the reasoning by the SDT for including it in 1.2 and 1.4 but not in 1.3. Additionally, EEI does not agree that the insertion of 2.6 into 1.3 changes the impact ratings of the BCS at Transmission Facilities at a single station or substation location that are identified by the RC, PC or TP as critical to the derivation of IROLs. What has changed is the affected Transmission Operator Control Centers and backup Control Centers that monitor those facilities. For these reasons, we offer the following edits in bold face to the Industry Need section below:*

Criterion 1.3 needs to have Criterion 2.6 **inserted** into Criterion 1.3 for the Transmission Operator (TOP) to ensure proper high-impact categorization of BES Cyber System(s) related to Transmission **Operator Control Centers or backup Control Centers that perform the TOP function for assets that meet Criterion 2.6** are identified as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies as also required of the Balancing Authority (BA) in Criterion 1.2 and the Generator Operator (GOP) in Criterion 1.4.

Purpose or Goal (Section): *EEI also asks that the SDT modify some of the language and implied scope as contained in the Purpose or Goal section to address similar mentioned stated in our comments for the Industry Needs section above. (See our proposed edits in bold below).*

The proposed project will require the TOP to categorize its **Control Center (and backup Control Center)** BES Cyber System(s) as high impact that meet Criterion 2.6, as is also required of the BA and GOP in Criterion 1.2 and 1.4, respectively. (*Suggest removing sentence beginning with "By including Criterion 2.6 in Criterion 1.3*)

Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

NV Energy agrees that the scope is appropriate to achieve the stated purpose.

However, NV Energy notes a disconnect between the three items of the project scope and the two deliverables. We suggest re-numbering Deliverables 1 and 2 to 2 and 3 to correspond with the Project Scope and insert a new Deliverable 1 to determine if Criterion 2.6 was deliberately removed from Criterion 1.3 in draft 2 of CIP-002-5, or if there exists current justification for maintaining the omission.

As currently written, the SAR is directing implementation of Project Scope items 2 and 3 without first satisfying item 1. Project 2021-03 should first determine whether Criterion 2.6 should only require medium impact for TOP Control Centers given no cited impact to the reliability of the BES over the last 7 years.

NV Energy is concerned that a TOP operating a medium impact Control Center may have to elevate the Control Center's categorization to high impact based on a transient Transmission Substation IROL declaration that could take place any given year but, due to changes in grid topology, be rescinded the following year.

NV Energy understands that Project 2021-03 is currently revising Criterion 2.6 under task 2 to address this issue by adding a qualifier to IROLs limiting the Criterion to those "expected to last 36 months or longer from the date of RC provision of notice." We urge that these efforts be coordinated to address both issues simultaneously.

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

Recommend this revision be incorporated into a larger CIP-002 standard revision project.

Please consider updating implementation timelines and impact if there is a responsible entity that changes from a lower impact to a higher impact scope. The implementation plan should start 24 calendar months from the entity's first CIP-002 R2 review post the effective date.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	

Comment

Texas RE supports this Standard Authorization Request (SAR).

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports EEI's comments, as well as acknowledges that including criterion 2.6 in criterion 1.3 does not change current categorization of control centers. However, Ameren is concerned that the "Project Scope" indicated in Step 3 of this SAR lacks the appropriate level of specificity and may cause unintended interpretations and impact to other CIP standards and associated documents.	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
The ISO/RTO Council Standards Review Committee (SRC) supports NERC's intention to align criterion 1.3 with criteria 1.2 and 1.4 in CIP-002-5.1a, Attachment 1. However, the SRC sees the existing misalignment as a low risk to the reliability and security of the BES, and therefore believes that this SAR is a lower priority than most other SARs currently being addressed by NERC Reliability standard projects. Other criteria in CIP-002-5.1a already capture the majority of Control Centers and backup Control Centers that would be impacted by the proposed revision to criterion 1.3, and only a few additional entities, with low impact to the BES, are likely to be affected by this proposed SAR. Therefore, the SRC recommends that the priority level of this SAR be set appropriately. Since the current Reliability Standards Process does not consider the relative risk and urgency of proposed Reliability standards, the industry resources that will be needed to address this proposed SAR need to be weighed with the reliability impacts of the issue the SAR proposes to address relative to the numerous other SARs currently being addressed in Reliability standards projects.	
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 Standards Review Committee (SRC) and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, 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	
Karla Weaver - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Georgia Transmission Corporation - 1 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matt Lewis - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 5,6	
Answer	
Document Name	
Comment	
These changes have no impact on Constellation Generation, therefore Constellation does not have additional comments. Kimberly Turco on behalf of Constellation Energy Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	

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

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
ACES would like to thank the SDT for allowing us to comment	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 1,3,6	
Answer	
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	
We do acknowledge an inconsistency. It is difficult to keep straight the different projects and SARs impacting CIP-002 in parallel. We recommend NERC consider revising the NERC Rules of Procedure or Standards Process Manual to establish a formalized process for evaluating the feasibility of consolidating projects when a single standard is impacted by multiple SARS and separate Standard Drafting Teams (SDTs). We also recommend NERC consider a common mode of communication with all stakeholders when projects are consolidated. Consolidating projects tied to the same standard not only paves the way for enhanced uniformity and consistency but also improves the efficiency of the SDT and industry review process. It may also prevent administrative issues such as the one indicated by the need for this SAR.	

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment

Given the magnitude of increased compliance obligations Transmission Operators that currently only operate medium impact Control Centers may face as a result of this project, NV Energy recommends a 36-month Implementation Plan for this part of the project.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 1,3

Answer	
Document Name	

Comment

Exelon is aligning with EEI in response to this question.

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5

Answer	
Document Name	

Comment

We do acknowledge an inconsistency.
It is difficult to keep straight the different projects and SARs impacting CIP-002 in parallel.
We recommend NERC consider revising the NERC Rules of Procedure or Standards Process Manual to establish a formalized process for evaluating the feasibility of consolidating projects when a single standard is impacted by multiple SARS and separate Standard Drafting Teams (SDTs). We also recommend NERC consider a common mode for communication to all stakeholders when projects are consolidated. Consolidating projects tied to the

same standard not only paves the way for enhanced uniformity and consistency but also improves the efficiency of the SDT and industry review process. It may also prevent administrative issues such as the one indicated by the need for this SAR.

Likes 0	
Dislikes 0	

Response

Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC

Answer	
Document Name	

Comment

We do acknowledge an inconsistency.

It is difficult to keep straight the different projects and SARs impacting CIP-002 in parallel.

We recommend NERC consider revising the NERC Rules of Procedure or Standards Process Manual to establish a formalized process for evaluating the feasibility of consolidating projects when a single standard is impacted by multiple SARS and separate Standard Drafting Teams (SDTs). We also recommend NERC consider a common mode for communication to all stakeholders when projects are consolidated. Consolidating projects tied to the same standard not only paves the way for enhanced uniformity and consistency but also improves the efficiency of the SDT and industry review process. It may also prevent administrative issues such as the one indicated by the need for this SAR.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 1,5

Answer	
Document Name	

Comment

None at this time.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
Given the magnitude of increased compliance obligations Transmission Operators that currently only operate medium impact Control Centers may face as a result of this project, the MRO NSRF recommends a 36-month Implementation Plan for this part of the project.	
Likes 0	
Dislikes 0	
Response	

Alain Mukama - Hydro One Networks, Inc. - 1,3	
Answer	
Document Name	
Comment	
As this SAR is minor, it would be more effective to incorporate this change along with other approved change proposal into a larger CIP-002 standard revision project.	
Likes 0	
Dislikes 0	
Response	

Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6	
Answer	
Document Name	
Comment	
AZPS no addtional comments for the Standard drafting team to consider at this time.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Minnkota Power Cooperative Inc. - 1,5 - MRO	
Answer	
Document Name	
Comment	
MPC supports the comments submitted by the MRO NERC Standards Review Forum (NSRF).	
Likes 0	
Dislikes 0	
Response	

Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Unofficial Nomination Form

Project 2021-03 CIP-002

Do not use this form for submitting nominations. Use the electronic form to submit nominations for **supplemental Project 2021-03 CIP-002 drafting team members** by **8 p.m. Eastern, Monday July 31, 2023.** 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 Love (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.

Background

There are currently four (4) Standards Authorization Requests (SARs) assigned to the project. The project currently contains two (2) groups:

- Group A that has a focus on CIP-002-5.1a criterion 2.12;
- Group B that has a focus on the remaining three (3) SARs:
  - CIP-002 and CIP-014 - By modifying the standards to replace/update language with regards to "critical to the derivation of the Interconnection Reliability Operating Limits to appropriately identify Facilities.
  - CIP-002 Communication Protocol Converters - Include the identification of communication protocol converters and the relationship to the exception in Section 4.2.3 in CIP-002.
  - Modifications to CIP-002 **-** To ensure all BES Cyber Systems' associated Cyber Assets (CA) are identified for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those CA.

Nominations are being sought for Group B supplemental members with subject matter expertise who can address the CIP-002 Communication Protocol Converters SAR along with the remaining SARs.

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

- Transmission and Generation Owners;
- Transmission and Generation Operations;
- Familiarity with system-to-system serial communication protocol converters;

- Familiarity with NERC Standard CIP-002;
- Other tasks for owning, enforcing, and managing of communication protocol converters between both transmission and generation architectures.

Standard(s) affected: CIP-002 and CIP-014

The time commitment for this project 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.

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: a

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

Provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group:			
Name:		Telephone:	
Organization:		Email:	
Name:		Telephone:	
Organization:		Email:	

Provide the name and contact information of your immediate supervisor or a member of your management who can confirm your organization's willingness to support your active participation.			
Name:		Telephone:	
Title:		Email:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC web site.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2021-03 CIP-002

Supplemental Drafting Team Nomination Period Open through August 18, 2023

Now Available

Nominations are being sought for Group B supplemental members through **8 p.m. Eastern, Friday, August 18, 2023**.

Use the electronic form to submit a nomination. Contact Wendy Muller regarding issues using the electronic form. The 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 conference calls and face-to-face meetings. Previous drafting team experience is beneficial but not required. See the project page and nomination form for additional information.

The time commitment for this project 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.

Next Steps

The Standards Committee is expected to appoint members to the drafting team in September 2023. Nominees will be notified shortly after they have been appointed.

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 2021-02 CIP-002 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 Development Timeline

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

Description of Current Draft

This is the initial draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September – November 2023

Anticipated Actions	Date
Final Ballot TOCC	December 2023
Board adoption	December 2023

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):

Control Center - One or more rooms where a responsible entity hosts operating personnel to monitor and control the Bulk Electric System (BES) in real-time, as described below, including any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time. Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units.

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;
2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;
3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations;
4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or
5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more locations in real-time.

A. Introduction

1. **Title:** Cyber Security — Bulk Electric System (BES) Cyber System Categorization
2. **Number:** CIP-002-Y
3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-Y:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See “Project 2021-03 CIP-002 Transmission Owners Control Centers Implementation Plan”

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

I. Control Centers and backup Control Centers;

II. Transmission stations and substations; Generation resources;

III. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;

IV. RAS that support the reliable operation of the BES; and

V. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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 CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

   - Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
   - If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
   - The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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

Violation Severity Levels

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Operations Planning	High	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not	a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Systems, more than 10 but less than or equal to 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not	fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
				been identified.	been identified.	
R2	**Operations Planning**	**Lower**	The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1) OR The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1 -Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.

1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. RAS or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:

2.11. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

<u>Exclusion:</u>
BES Transmission Lines monitored and controlled by the Control Center or backup Control Center may be excluded from the "aggregate weighted value" calculation if they are part of a local system that is operated at less than 300kV, where the net export from the local system does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The net export is based on the hourly integrated values for the most recent 12-month period.

2.13. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)
BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS that support the reliable operation of the BES.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002- 5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
Y	TBD		

Standard Development Timeline

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

Description of Current Draft

This is the initial draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with ballot	September – November 2023

Anticipated Actions	Date
Final Ballot TOCC	December 2023
Board adoption	December 2023

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):

Control Center - One or more ~~facilities~~ rooms where a responsible entity hosts ~~hosting~~ operating personnel ~~that~~ to monitor and control the Bulk Electric System (BES) in real-time, as described below, ~~to perform the reliability tasks,~~ including any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time. Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units.~~their associated data centers, of:~~

1) Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;~~,~~

2) Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;~~,~~

3) Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for ~~t~~Transmission Facilities at two or more locations;

4) ~~,~~Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or

5) Operating personnel of a Generator Operator who have the capability to electronically control ~~for~~ generation Facilities at two or more locations in real-time.

A. Introduction

1. **Title:** Cyber Security — Bulk Electric System (BES) Cyber System Categorization

2. **Number:** CIP-002-~~5.1a~~Y

3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. ~~Each Special Protection System or~~ Remedial Action Scheme (RAS) where the ~~Special Protection System or Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

~~Interchange Coordinator or Interchange Authority~~

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. **Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. **Distribution Provider**: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. ~~Each Special Protection System or Remedial Action Scheme~~RAS where the ~~Special Protection System or Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. **Responsible Entities listed in 4.1 other than Distribution Providers**:

All BES Facilities.

4.2.3. **Exemptions:** The following are exempt from Standard CIP-002-~~5.1a~~Y:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See "Project 2021-03 CIP-002 Transmission Owners Control Centers Implementation Plan"

~~1. **24 Months Minimum** – CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~**6. Background:**~~

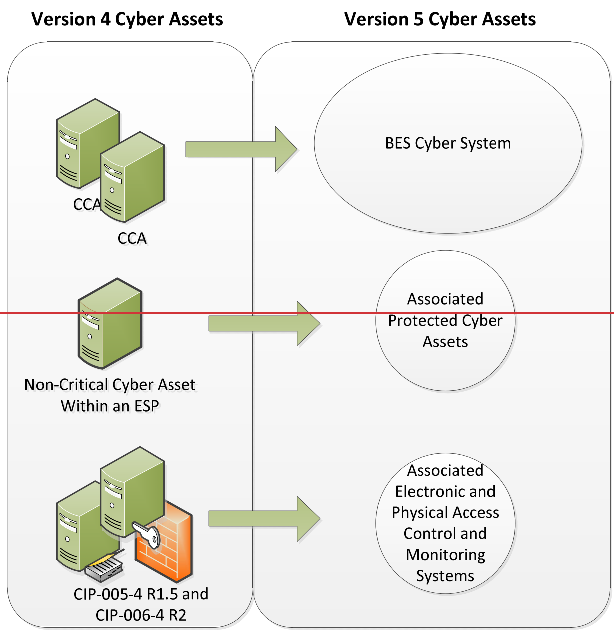
~~This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.~~

~~Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."~~

~~Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~**BES Cyber Systems**~~

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

~~Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.~~

~~It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System~~

~~boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~Reliable Operation of the BES~~

~~The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.~~

~~Real-time Operations~~

~~One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.~~

~~Categorization Criteria~~

~~The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.~~

~~This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.~~

~~Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems~~

~~BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic~~

~~Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:~~

~~**Electronic Access Control or Monitoring Systems ("EACMS")** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.~~

~~**Physical Access Control Systems ("PACS")**– Examples include: authentication servers, card systems, and badge control systems.~~

~~**Protected Cyber Assets ("PCA")** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.~~

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of ~~p~~Parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** ~~Special Protection Systems~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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. ~~The Regional Entity shall serve as the Compliance Enforcement Authority ("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

1.2. Evidence Retention:

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

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

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.

- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and ~~Assessment Processes~~Enforcement Program:

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

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

~~**1.4. Additional Compliance Information**~~

- ~~None~~

~~2. Table of Compliance Elements~~ Violation Severity Levels

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R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Operations Planning**	**High**	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities -with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber	For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly	For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber ~~Assets~~Systems, more than 10 but less than or equal to 15 identified BES Cyber ~~Assets~~Systems have not been categorized or have been	Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities -with more than a total of 100 high and medium impact BES Cyber

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.

R #	Time Horizon	VRF	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	**Operations Planning**	**Lower**	The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1) OR The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

~~CIP-002-5.1a~~Y ~~–~~ Attachment 1 – Impact Rating Criteria

~~**Impact Rating Criteria**~~

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

1.1. Each Control Center or backup Control Center used to perform the functional obligations of the Reliability Coordinator.

1.2. Each Control Center or backup Control Center used to perform the functional obligations of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. Each Control Center or backup Control Center used to perform the functional obligations of the Transmission Operator for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center used to perform the functional obligations of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are ~~those~~each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are ~~those~~each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

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2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. ~~Each Special Protection System (SPS), Remedial Action Scheme (~~RAS~~),~~ or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:

2.11. Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. Each Control Center or backup Control Center ~~used to perform the functional obligations of the~~ , operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H~~),~~) above~~.~~, with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0

Exclusion:

BES Transmission Lines monitored and controlled by the Control Center or backup Control Center may be excluded from the "aggregate weighted value" calculation if they are part of a local system that is operated at less than 300kV, where the net export from the local system does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The net export is based on the hourly integrated values for the most recent 12-month period.

~~2.12.~~**2.13.** Each Control Center or backup Control Center, not already included in High Impact Rating (H) above, used to perform the functional obligations of the Balancing

Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. ~~Special Protection Systems~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

~~Guidelines and Technical Basis~~

~~Section 4 – Scope of Applicability of the CIP Cyber Security Standards~~

~~Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.~~

~~Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.~~

~~Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.~~

~~For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.~~

~~CIP-002-5.1a~~

~~CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."~~

~~The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber~~

~~Systems that would be subject to CIP-002-5.1a. The concept includes a number of named BES reliability operating services. These named services include:~~

~~Dynamic Response to BES conditions~~
~~Balancing Load and Generation~~
~~Controlling Frequency (Real Power)~~
~~Controlling Voltage (Reactive Power)~~
~~Managing Constraints~~
~~Monitoring & Control~~
~~Restoration of BES~~
~~Situational Awareness~~
~~Inter-Entity Real-Time Coordination and Communication~~

~~Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.~~

~~Entity Registration~~	~~RC~~	~~BA~~	~~TOP~~	~~TO~~	~~DP~~	~~GOP~~	~~GO~~
~~Dynamic Response~~		~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Balancing Load & Generation~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Controlling Frequency~~		~~X~~				~~X~~	~~X~~
~~Controlling Voltage~~			~~X~~	~~X~~	~~X~~		~~X~~
~~Managing Constraints~~	~~X~~		~~X~~			~~X~~	
~~Monitoring and Control~~			~~X~~			~~X~~	
~~Restoration~~			~~X~~			~~X~~	
~~Situation Awareness~~	~~X~~	~~X~~	~~X~~			~~X~~	
~~Inter-Entity coordination~~	~~X~~	~~X~~	~~X~~	~~X~~		~~X~~	~~X~~

~~Dynamic Response~~

~~The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:~~

- ~~Spinning reserves (contingency reserves)~~
  - ~~Providing actual reserve generation when called upon (GO,GOP)~~
  - ~~Monitoring that reserves are sufficient (BA)~~
- ~~Governor Response~~
  - ~~Control system used to actuate governor response (GO)~~
- ~~Protection Systems (transmission & generation)~~
  - ~~Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)~~
  - ~~Zone protection for breaker failure (DP, TO, TOP)~~
  - ~~Breaker protection (DP, TO, TOP)~~
  - ~~Current, frequency, speed, phase (TO,TOP, GO,GOP)~~
- ~~Special Protection Systems or Remedial Action Schemes~~
  - ~~Sensors, relays, and breakers, possibly software (DP, TO, TOP)~~
- ~~Under and Over Frequency relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Under and Over Voltage relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Power System Stabilizers (GO)~~

~~Balancing Load and Generation~~

~~The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:~~

- ~~Calculation of Area Control Error (ACE)~~
  - ~~Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)~~
  - ~~Software used to perform calculation (BA)~~
- ~~Demand Response~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP,DP)~~
- ~~Manually Initiated Load shedding~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP, DP)~~

- ~~Non-spinning reserve (contingency reserve)~~
  - ~~Know generation status, capability, ramp rate, start time (GO, BA)~~
  - ~~Start units and provide energy (GOP)~~

~~Controlling Frequency (Real Power)~~

~~The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:~~

- ~~Generation Control (such as AGC)~~
  - ~~ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)~~
  - ~~Software to calculate unit adjustments (BA)~~
  - ~~Transmit adjustments to individual units (GOP)~~
  - ~~Unit controls implementing adjustments (GOP)~~
- ~~Regulation (regulating reserves)~~
  - ~~Frequency source, schedule (BA)~~
  - ~~Governor control system (GO)~~

~~Controlling Voltage (Reactive Power)~~

~~The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:~~

- ~~Automatic Voltage Regulation (AVR)~~
  - ~~Sensors, stator control system, feedback (GO)~~
- ~~Capacitive resources~~
  - ~~Status, control (manual or auto), feedback (TOP, TO,DP)~~
- ~~Inductive resources (transformer tap changer, or inductors)~~
  - ~~Status, control (manual or auto), feedback (TOP,TO,DP)~~
- ~~Static VAR Compensators (SVC)~~
  - ~~Status, computations, control (manual or auto), feedback (TOP, TO,DP)~~

~~Managing Constraints~~

~~Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:~~

- ~~Available Transfer Capability (ATC) (TOP)~~
- ~~Interchange schedules (TOP, RC)~~
- ~~Generation re-dispatch and unit commit (GOP)~~
- ~~Identify and monitor SOL's & IROL's (TOP, RC)~~
- ~~Identify and monitor Flow gates (TOP, RC)~~

~~Monitoring and Control~~

~~Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:~~

- ~~All methods of operating breakers and switches~~
  - ~~SCADA (TOP, GOP)~~
  - ~~Substation automation (TOP)~~

~~Restoration of BES~~

~~The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:~~

- ~~Restoration including planned cranking path~~
  - ~~Through black start units (TOP, GOP)~~
  - ~~Through tie lines (TOP, GOP)~~
- ~~Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)~~
- ~~Coordination (TOP, TO, BA, RC, DP, GO, GOP)~~

~~Situational Awareness~~

~~The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:~~

- ~~Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)~~
- ~~Change management (TOP,GOP,RC,BA)~~
- ~~Current Day and Next Day planning (TOP)~~
- ~~Contingency Analysis (RC)~~
- ~~Frequency monitoring (BA, RC)~~

~~Inter-Entity Coordination~~

~~The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:~~

- ~~Scheduled interchange (BA,TOP,GOP,RC)~~
- ~~Facility operational data and status (TO, TOP, GO, GOP, RC, BA)~~
- ~~Operational directives (TOP, RC, BA)~~

~~Applicability to Distribution Providers~~

~~It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.~~

~~Requirement R1:~~

~~Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.~~

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

~~Attachment 1~~

~~Overall Application~~

~~In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.~~

- ~~When the drafting team uses the term "Facilities", there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.~~
- ~~In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.~~
- ~~It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.~~

~~High Impact Rating (H)~~

~~This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some~~

~~of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.~~

~~The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.~~

~~Additional thresholds as specified in the criteria apply for this category.~~

~~Medium Impact Rating (M)~~

~~Generation~~

~~The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.~~

- ~~Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.~~

  ~~In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.~~

  ~~By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.~~

~~The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.~~

- ~~In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.~~

  ~~If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.~~

  ~~The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.~~

- ~~Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.~~

  ~~IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.~~

- ~~Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.~~

- ~~Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.~~

- ~~Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~Transmission~~

~~The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.~~

- ~~Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.~~

- ~~Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.~~

~~It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.~~

- ~~Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:~~

    - ~~Excluded radial facilities that would only provide support for single generation facilities.~~

    - ~~Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.~~

~~The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.~~

~~Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:~~

- ~~230 kV –> 700 MVA~~

- ~~345 kV –> 1,300 MVA~~

- ~~500 kV –> 2,000 MVA~~

- ~~765 kV –> 3,000 MVA~~

~~In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:~~

- ~~For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate~~

~~connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.~~

- ~~Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.~~

- ~~Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.~~

~~Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.~~

1. ~~The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.~~
2. ~~The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.~~

~~The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.~~

- ~~Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2,~~ ~~**Establish and Communicate System Operating Limits**~~~~, R5.1.1 and R5.1.3.~~

- ~~Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.~~

- ~~Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.~~

- ~~Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.~~

- ~~Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.~~

  ~~This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~In ERCOT, the Load acting as a Resource ("LaaR") Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.~~

~~The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.~~

- ~~Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.~~

- ~~Criterion 2.13 categorizes as Medium Impact those BA Control Centers that "control" 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~Low Impact Rating (L)~~

~~BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.~~

~~Restoration Facilities~~

- ~~Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.~~

  ~~In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.~~

  ~~The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.~~

~~Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.~~

~~BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.~~

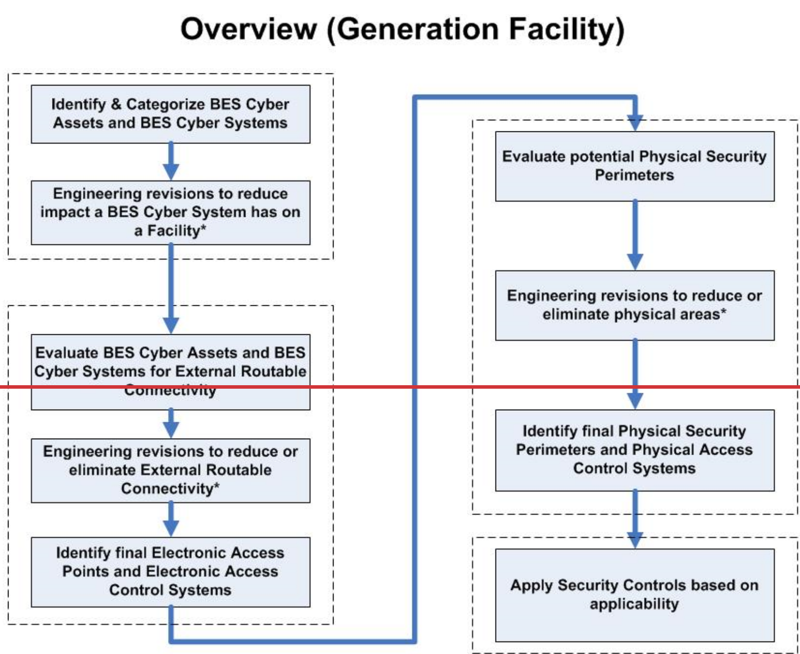
~~Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."~~

- ~~BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.~~

  ~~Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.~~

~~**Use Case: CIP Process Flow**~~

~~The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.~~



* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

~~Rationale:~~

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

~~Rationale for R1:~~

~~BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of "bright-line" criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.~~

~~Rationale for R2:~~

~~The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager's approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.~~

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3.	Update

		Approved by the NERC Board of Trustees.	
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
Y	TBD		

~~**Appendix 1**~~

~~**Requirement Number and Text of Requirement**~~
~~CIP-002-5.1, Requirement R1~~ ~~R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:~~ ~~i. Control Centers and backup Control Centers;~~ ~~ii. Transmission stations and substations;~~ ~~iii. Generation resources;~~ ~~iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;~~ ~~v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and~~ ~~vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.~~ ~~1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;~~ ~~1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and~~ ~~1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).~~ ~~Attachment 1, Criterion 2.1~~ ~~2. Medium Impact Rating (M)~~ ~~Each BES Cyber System, not included in Section 1 above, associated with any of the following:~~ ~~2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.~~

~~**Questions**~~
~~Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."~~ ~~The Interpretation Drafting Team identified the following questions in the RFI:~~ ~~1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~ ~~2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~ ~~3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~
~~**Responses**~~
~~**Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?**~~ ~~The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)~~ ~~Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:~~ ~~The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~**Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?**~~

~~The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.~~

~~The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:~~

> ~~Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.~~

~~**Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?**~~

~~The phrase applies to each discrete BES Cyber System.~~

Implementation Plan

Project 2021-03 CIP-002 | Reliability Standard CIP-002-Y

Applicable Standard(s)

- Reliability Standard CIP-002-Y – Cyber Security -Bulk Electric System (BES) Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-5.1a – Cyber Security - BES Cyber System Categorization

Prerequisite Standard(s)

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

- None

Applicable Entities

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

Modified 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 Modified Definition(s):

Control Center – One or more rooms where a responsible entity hosts operating personnel to monitor and control the BES in real-time, as described below, including any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time. Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units.

(1) Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

(2) Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

(3) Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations;

(4) Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or

(5) Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more locations in real-time.

Background

Project 2021-03 addresses modifications to Reliability Standard CIP-002-5.1a to clarify the characterization of BES Cyber Systems associated with Control Centers used to perform the functional obligations of the Transmission Operator. Specifically, Project 2021-03 includes revisions to CIP-002 Criterion 2.12 in Attachment 1 and the Control Center definition. The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers performing the functional obligations of a Transmission Operator. These modifications resulted from recommendations from the CIP-002 Transmission Owner Control Center Field Test Report.[1]

General Considerations

This Implementation Plan includes phased-in implementation dates for Criterion 2.12 of CIP-002-Y, Attachment 1. The phased-in implementation dates allow Responsible Entities[2] a longer implementation period if the revisions to the criterion would result in a higher impact level categorization of a BES Cyber System.

Effective Date and Phased-In Compliance Dates

The effective date for proposed Reliability Standard CIP-002-Y and the modified definition is 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 of it), the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible 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.

[1] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

[2] As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

Reliability Standard CIP-002-Y – Cyber Security – BES Cyber System Categorization

Where approval by an applicable governmental authority is required, the standard shall become effective on the first day of the first calendar quarter that is three (3) 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 three (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Dates for CIP-002-Y

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-Y, Requirement R2 within 15 calendar months of their last performance of Requirement R2 under CIP-002-5.1a.

Phased-in Implementation Date for CIP-002-Y, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criterion 2.12 of Attachment 1 to CIP-002-Y result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as that higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP-002-Y. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a, Requirement R1, Part 1.3.

Planned or Unplanned Changes

The planned and unplanned change provisions in the Implementation Plan associated with CIP-002-5.1a shall apply to CIP-002-Y. The Implementation Plan associated with CIP-002-5.1a[3] provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard):

Planned Changes

Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-Y, Requirement R2. For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-Y, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

For planned changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and

[3] The Implementation Plan associated with CIP-002-5.1a is available at https://www.nerc.com/pa/Stand/Project%20200806%20Cyber%20Security%20Order%20706%20DL/Implementation_Plan_clean_4_(2012-1024-1352).pdf.

categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section Initial Performance of Certain Periodic Requirements of the CIP-002-5.1a Implementation Plan.

Unplanned Changes

Unplanned changes refer to any changes of the electric system or BES Cyber System which were not planned by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-Y, Requirement R2.

For example, consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-Y, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-Y, Attachment 1, criteria.

For unplanned changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section Initial Performance of Certain Periodic Requirements of the CIP-002-5.1a Implementation Plan.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to Medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System	12 months
Responsible Entity identifies its first high impact or medium impact BES Cyber System (i.e., the Responsible Entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002 identification and categorization processes)	24 months

Control Center Definition

Where approval by an applicable governmental authority is required, the definition shall become effective on the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving Reliability Standard CIP-002-Y, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the definition shall become effective on the first day of the first calendar quarter that is three (3) months after the date that Reliability Standard CIP-002-Y is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-Y in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2021-03 CIP-002

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **CIP-002-Y — Cyber Security — BES Cyber System Categorization** by **8 p.m. Eastern, Thursday, November 9, 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

Project 2021-03 currently has five assigned Standard Authorization Requests (SARs). The proposed standard revisions are based on the Project 2016-02 Modifications to CIP Standards SAR which seeks to modify Reliability Standard CIP-002 to address the categorization of certain Transmission Owner Control Centers performing Transmission Operator functions as medium impact based on an aggregate weighted value of their BES Transmission Lines in Criterion 2.12. The remaining four SARs will be addressed at a later date.

The Standards Committee (SC) assigned a portion of the Project 2016-02 SAR to the Project 2021-03 standard drafting team (SDT) at its March 17, 2021 meeting. In addition, the SDT assisted NERC staff in meeting the directive from the NERC Board of Trustees to conduct further study of the need to readdress the applicability of the Critical Infrastructure Protection Reliability Standards to theses Control Centers to support reliability. To help meet this directive and the scope of the SAR, the SDT initiated a field test. The SC approved the Project 2021-03 Field Test Plan on November 17, 2021. Three fields tests were conducted in 2022 and the final report was posted to the project page in January 2023. Lastly, the SDT conducted an informal comment period from June 13 – July 12, 2023 to solicit feedback on proposed standard language.

Summary of changes Overview

The SDT made modifications to the Reliability Standard and Control Center Definition accordingly. For a detailed explanation of these changes, please refer to the *CIP-002-Y Technical Rationale*.

There are currently two drafting teams working on modifications to CIP-002-5.1a. The Project 2021-03 SDT is posting modifications as CIP-002-Y to differentiate its work from Project 2016-02 Modifications to CIP Standards (CIP-002-7).

In addition, the proposed revised 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 revised definition used in the standard.

Questions

1. The SDT has modified the Control Center definition based on ambiguity that surfaced during the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

2. The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". This was intentional, to make clear that the BES Cyber Systems to consider differ between Control Centers and other assets such as Transmission stations and Generation resources. In alignment with Part 1 of Attachment 1, BES Cyber Systems 'used by and located at' Control Centers need to be considered. This prevents expanding from Control Centers down into field assets. With respect to other assets, it is BES Cyber Systems 'associated with' the assets that are considered. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

3. The SDT revised CIP-002-Y Attachment 1 Criterion 2.12 based on data obtained from the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

4. Provide any additional comments for the SDT to consider, if desired.

   Comments:

Technical Rationale

Project 2021-03 CIP-002 | Reliability Standard CIP-002-Y

Control Center Definition and CIP-002-Y– Cyber Security – Bulk Electric System (BES) Cyber System Categorization

Introduction

This document explains the technical rationale and justification for the proposed revisions to the Control Center Definition and Reliability Standard CIP-002-Y. It provides stakeholders and the ERO Enterprise with a description of the technical requirements in the Reliability Standard. These are not Reliability Standards and should not be considered mandatory and enforceable.

Updates to this document include the Project 2021-03 CIP-002 Standards Drafting Team's (SDT's) intent in drafting changes to the requirements and definition.

Overview

Project 2021-03 proposes revisions to the Control Center definition and CIP-002-Y Criterion 2.12 in Attachment 1. CIP-002-Y provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the BES. The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers (TOCCs) performing the functional obligations of a Transmission Operator, specifically those that meet medium impact criteria, and clarifying the language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.

Rationale for Control Center Definition Modifications

Rationale for Proposing Modifications to the Control Center Definition

During the CIP-002 TOCC Field Test[1], it was found that many Transmission Owners struggled with how to interpret the Control Center definition. While the current Control Center definition does not specifically identify Transmission Owners, a Transmission Owner may have a Control Center through its ability to monitor and control the BES in real-time to perform the reliability tasks of a Transmission Operator. This struggle surfaced in the following three manners:

- Lack of a common understanding of the term "control" versus "authority".
- Lack of a common understanding of the term "perform the functional obligations of the Transmission Operator" as stated in Attachment 1 of CIP-002-5.1a.
- Lack of a common understanding of the term "associated data centers".

[1] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

Modifications to the definition have been proposed to eliminate ambiguity.

Applicable Control Center Entities

The revised Control Center definition is structured to explicitly identify the five different types of registered entities that could have a Control Center.

For Reliability Coordinator, Balancing Authority and Transmission Operator entities, the operating personnel are specifically identified as those individuals who perform Real-time reliability-related tasks. Any rooms that host these operating personnel to monitor and control the BES in real-time are part of the Control Center.

For Transmission Owner and Generator Operator entities, any rooms that host operating personnel having the capability to electronically control Facilities at two or more locations in real-time are part of the Control Center. The term “capability” is specifically used to clarify that a Transmission Owner or Generator Operator that monitors its Facilities without any capability to control those Facilities does not fall within the Control Center definition. Further, the use of the phrase “electronically control” is intended differentiate between an entity who is able to remotely control BES Facilities in real-time (e.g., via a SCADA system) and an entity who is only able to control BES Facilities via field personnel (e.g., via radio or telephone). An entity who is only able to control BES Facilities via field personnel would not fall within the Control Center definition.

When considering the language ‘Facility at two or more locations’, it is generally expected that the Facilities will have separate street addresses. Facilities located at a single street address would be associated with a single location.

Associated Data Centers

The present Control Center definition includes the phrase “associated data centers”. This phrasing was originally intended to ensure the Cyber Assets not co-located in the rooms that host operating personnel are included in the Control Center definition and thus are included in the process of identifying and categorizing BES Cyber Systems.

With the lack of a NERC definition for data center and a wide variety of interpretations, the term “associated data centers” either needed to be defined or needed to be replaced with language that describes the Cyber Assets that need to be included in the Control Center Definition. The phrase “any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time” was developed to replace “associated data center”.

A space that houses Cyber Assets used by operating personnel to monitor and control the BES in real-time may be:

- located in the same room that houses operating personnel.
- located in a room that does not house operating personnel, but is in the same building as a room that houses operating personnel (shared street address).
- located in a separate building from any rooms that house operating personnel.

- located in a virtual setting.

Cyber Assets used by operating personnel to monitor and control the BES in real-time exclude any RTUs or data aggregation assets used to gather and communicate data to the Control Center. RTUs and data aggregation assets would be evaluated for Cyber Security requirements based on their location and the data that they are gathering.

Rationale for Language to Differentiate Between Control Centers and Other Assets
The preface "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:" was inserted into Attachment 1 of CIP-002 between Criterion 2.10 and 2.11. This was intentional to make clear that the BES Cyber Systems to consider differ between Control Centers and other assets such as Transmission stations and Generation resources. In alignment with Part 1 of Attachment 1, BES Cyber Systems 'used by and located at' Control Centers need to be considered. This prevents expanding from Control Centers down into field assets. With respect to other assets, it is BES Cyber Systems 'associated with' the assets that are considered.

Rationale for CIP-002-Y Attachment 1 Criterion 2.12 Modifications

Aggregate Weighted Value
The total aggregate weighted value is used to account for the impact on the BES. The 6,000 aggregate weighted value threshold defined in criterion 2.12 provides sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that are operated by a registered Transmission Operator or owned by a registered Transmission Owner. SDT analysis of data obtained from the CIP-002 Transmission Owner Control Center Field Test[2] validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

The total aggregate weighted value of 6,000 was derived based on an entity with no single station or substation that meets criterion 2.5, but who has the capability or authority to control BES Transmission Lines with the equivalent weight of two stations or substations whose BES Cyber Systems would be classified as medium impact per criterion 2.5. This is ultimately derived from the "two or more locations" criteria that is documented in the Control Center definition.

The weight values per line were selected to align with the process that was originally used to establish the weight values per line for criterion 2.5. For BES Transmission Lines 200 kV to 499 kV, the weight values per line of 700 and 1300, respectively, were retained for consistency with criterion 2.5. Similar average MVA line loadings based on kV rating were calculated for BES Transmission Lines less than 100 kV and for BES Transmission Lines 100 kV to 199 kV using Appendix A of NERC's Severity Risk Index Enhancements Report which result in values of 100 and 250, respectively.

For the purpose of identifying a Responsible Entity's BES Transmission Lines, a Transmission Line is typically defined by the protection system(s) that would be used to isolate faults on the Transmission Line,

[2] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

which is generally defined by a boundary of fault interrupting devices (e.g., breakers). Transmission Lines can be single-ended, two-ended or three-ended.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages less than 100 kV that are monitored and controlled by a Control Center, and that have been specifically designated as part of the BES via the Rules of Procedure Exception Process.
- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV that are monitored and controlled by a Control Center, including BES Transmission Lines that connect to neighboring entities.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line. For example, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregate weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. For example, two 345 kV lines between two Transmission stations or substations would contribute an aggregate weighted value of 2,600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

BES Transmission Lines that are energized at voltages of 500 kV and above have no contribution to the aggregated weighted value given that criterion 2.4 already includes BES Cyber Systems for any Transmission Facilities at substations that are operated at 500 kV or higher as medium impact. Further, criterion 1.3 includes the BES Cyber Systems used by and located at Control Centers or backup Control Centers that monitor and control any BES Transmission Lines at substations that are operated at 500 kV or higher as high impact.

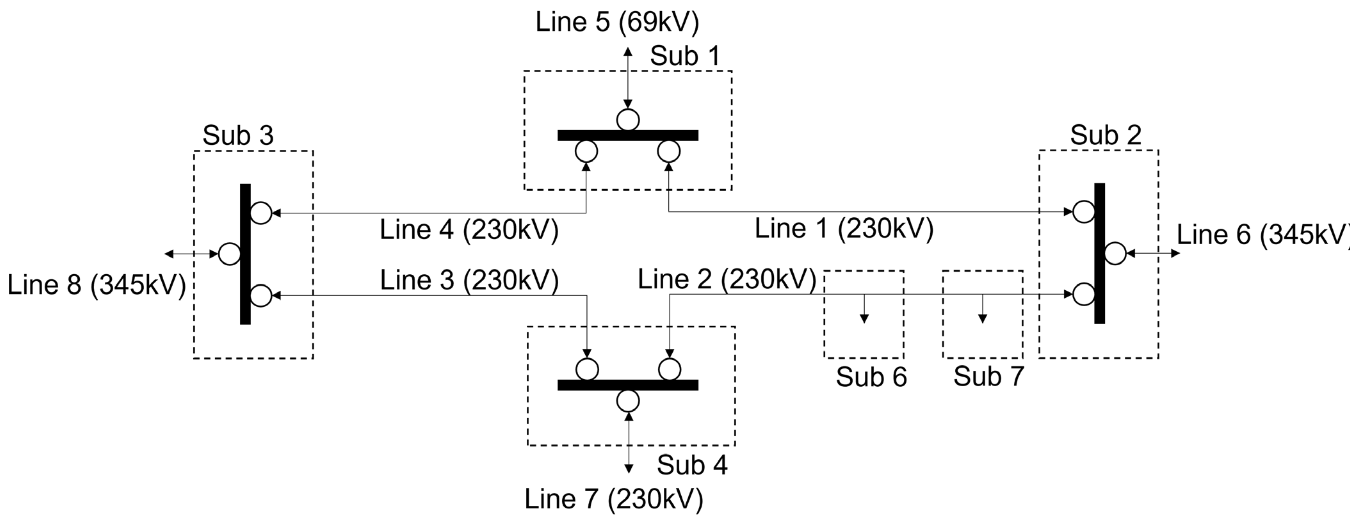
Exclusion Clause

The exclusion clause applies to Transmission Operators and Transmission Owners operated at less than 300 kV, where the net export from the local system does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The purpose of the exclusion clause is to allow for a Responsible Entity to exclude BES Transmission Lines within a local system from the “aggregate weighted value” calculation if the net export does not exceed 75 MW during non- EEA conditions. This allows for categorization at an appropriate level commensurate with the associated risk for local systems that are primarily designed to serve load, and that do not have a reliability impact on the BES. The bright line of 75 MW was selected to align with pre-existing criteria including (1) the registration criteria for a Distribution Provider and (2) the registration criteria for a Generator Owner.

EEA conditions were specifically excluded to ensure a Responsible Entity is not disincentivized from providing all available assistance during emergency conditions due to future compliance considerations.

Example 1

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6,100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

The circles on the diagram indicate the presence of fault interrupting devices. There are two substations shown (Sub 6, and Sub 7) that are tapped on Line 2 for load serving purposes; however, these substations do not have fault interrupting devices that will operate for a fault on Line 2. Therefore, the BES Transmission Line is defined between Sub 2 and Sub 4.

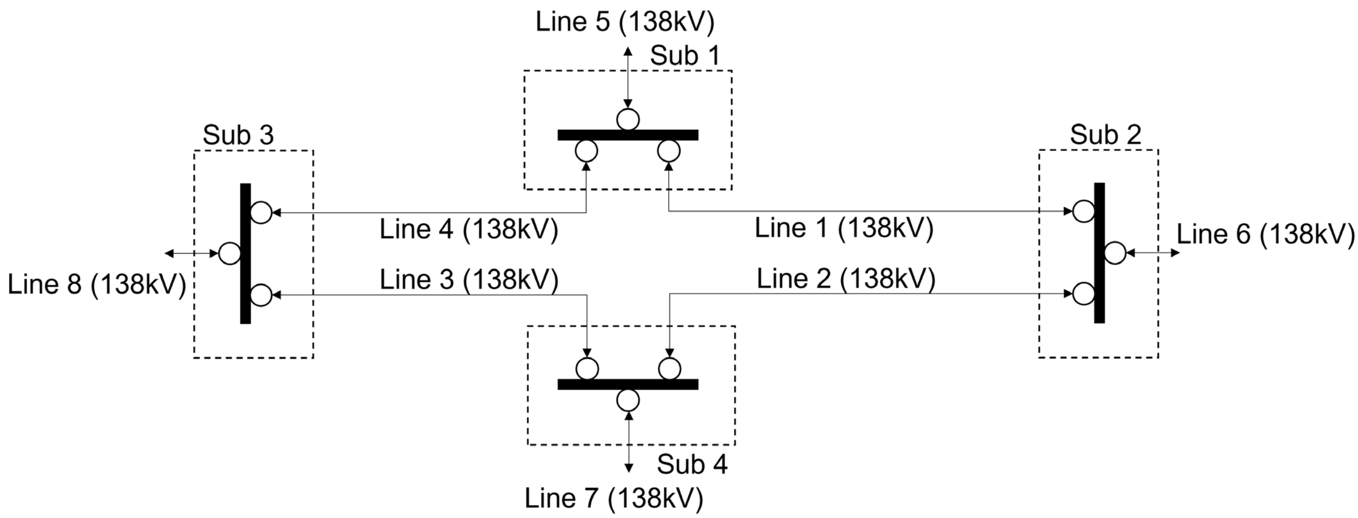
Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

* Line five is less than 100 kV; however, no exception has been obtained through the NERC Rules of Procedure Exception Process and therefore, the line is not BES.

Calculation
700+700+700+700+700+1300+1300 = 6100

Example 2

In example 2 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

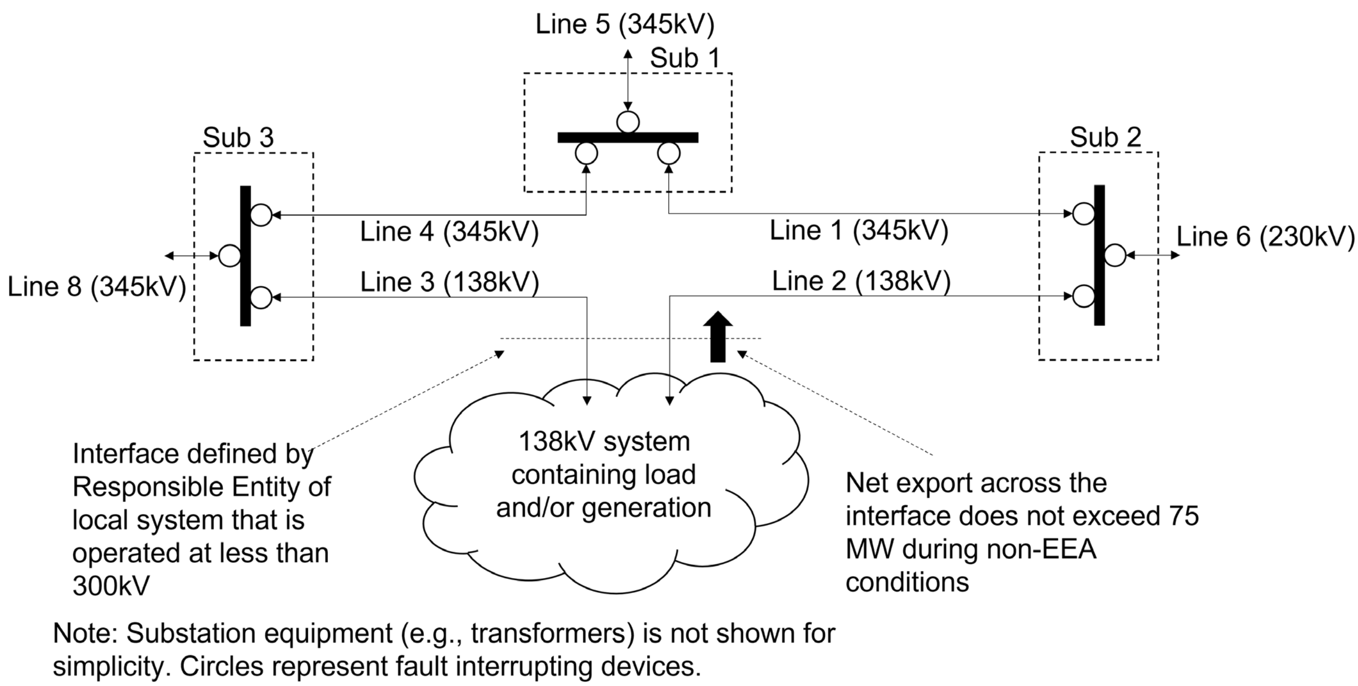
The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2,000, which is below the minimum threshold for the medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6 Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

<u>Calculation</u>

250+250+250+250+250+250+250+250 = 2000

Example 3
In example 3 below, BES Cyber System(s) are associated with a Control Center that monitors and controls five BES Transmission Lines that have not been excluded from the calculation. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12, and the exclusion language, and sum the weighted values for each BES Transmission Line that has been defined by the Responsible Entity and that does not meet the exclusion clause.



The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 5,900, which is below the minimum threshold for the medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a Line	Weight Value per Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 6	700
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 8	5200
500 kV and above	0	None	0

* Lines 2 and 3 (along with any additional lines located in the 138kV local system) are excluded from the calculation because the Responsible Entity has defined an interface to a local system that is operated at

less than 300kV, where the net export across the interface does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions.

Calculation
700+1300+1300+1300+1300 = 5900

Former Background Section from Reliability Standard CIP-002-5.1a

The Background section has been retired and removed from the standard and preserved by cutting and pasting as-is below.

Background

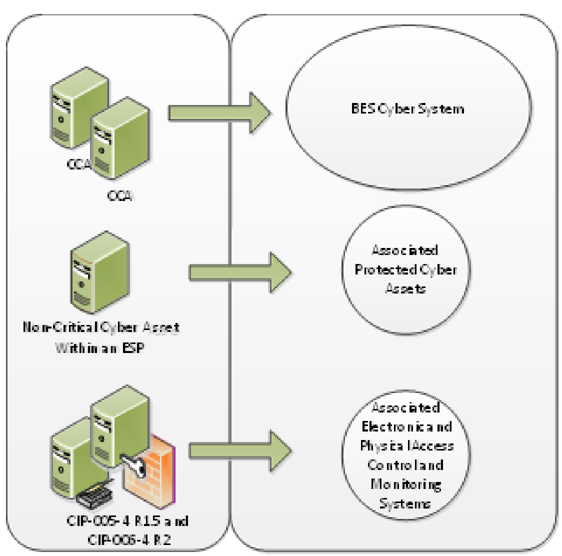
This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.



In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the “BES Cyber System” term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term “BES Cyber System” is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity’s responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than “Real-time,” BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

Electronic Access Control or Monitoring Systems (“ EACMS”)

Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.

Physical Access Control Systems (“ PACS”)

Examples include: authentication servers, card systems, and badge control systems.

Protected Cyber Assets (“ PCA”)

Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

Technical Rationale for Reliability Standard CIP-002-5.1a

This section contains a "cut and paste" of the former Guidelines and Technical Basis (GTB) as-is of from the CIP-002-5.1a standard to preserve any historical references. No modifications have been made.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002 -5 .1a

CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-5.1a. The concept includes a number of named BES reliability operating services. These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitor & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
  - Providing actual reserve generation when called upon (GO,GOP)
  - Monitoring that reserves are sufficient (BA)
- Governor Response
  - Control system used to actuate governor response (GO)
    - Protection Systems (transmission & generation)
  - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
  - Zone protection for breaker failure (DP, TO, TOP)
  - Breaker protection (DP, TO, TOP)
  - Current, frequency, speed, phase (TO,TOP, GO,GOP)
    - Special Protection Systems or Remedial Action Schemes
  - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
    - Under and Over Frequency relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
    - Under and Over Voltage relay protection (includes automatic load shedding)
  - Sensors, relays & breakers (DP)
    - Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
  - Field data sources (real time tie flows, frequency sources, time error, etc.) (TO, TOP)
  - Software used to perform calculation (BA)
- Demand Response
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP,DP)

- Manually Initiated Load shedding
    - Ability to identify load change need (BA)
    - Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
    - Know generation status, capability, ramp rate, start time (GO, BA)
    - Start units and provide energy (GOP)

Controlling Frequency (Real Power)

The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
    - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
    - Software to calculate unit adjustments (BA)
    - Transmit adjustments to individual units (GOP)
    - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
    - Frequency source, schedule (BA)
    - Governor control system (GO)

Controlling Voltage (Reactive Power)

The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
    - Sensors, stator control system, feedback (GO)
- Capacitive resources
    - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
    - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
    - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
  - SCADA (TOP, GOP)
  - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
  - Through black start units (TOP, GOP)
  - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)

- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA,TOP,GOP,RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

Attachment 1

Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

- When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

- In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.
- It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating (H)

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

  In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

  By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.
- The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.
- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In

particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

  IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.
- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.
- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

  It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.
- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
  - Excluded radial facilities that would only provide support for single generation facilities.
  - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation.

The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV –> 700 MVA
- 345 kV –> 1,300 MVA
- 500 kV –> 2,000 MVA
- 765 kV –> 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations

as well.

2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000. The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, Establish and Communicate System Operating Limits, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in

particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.
- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

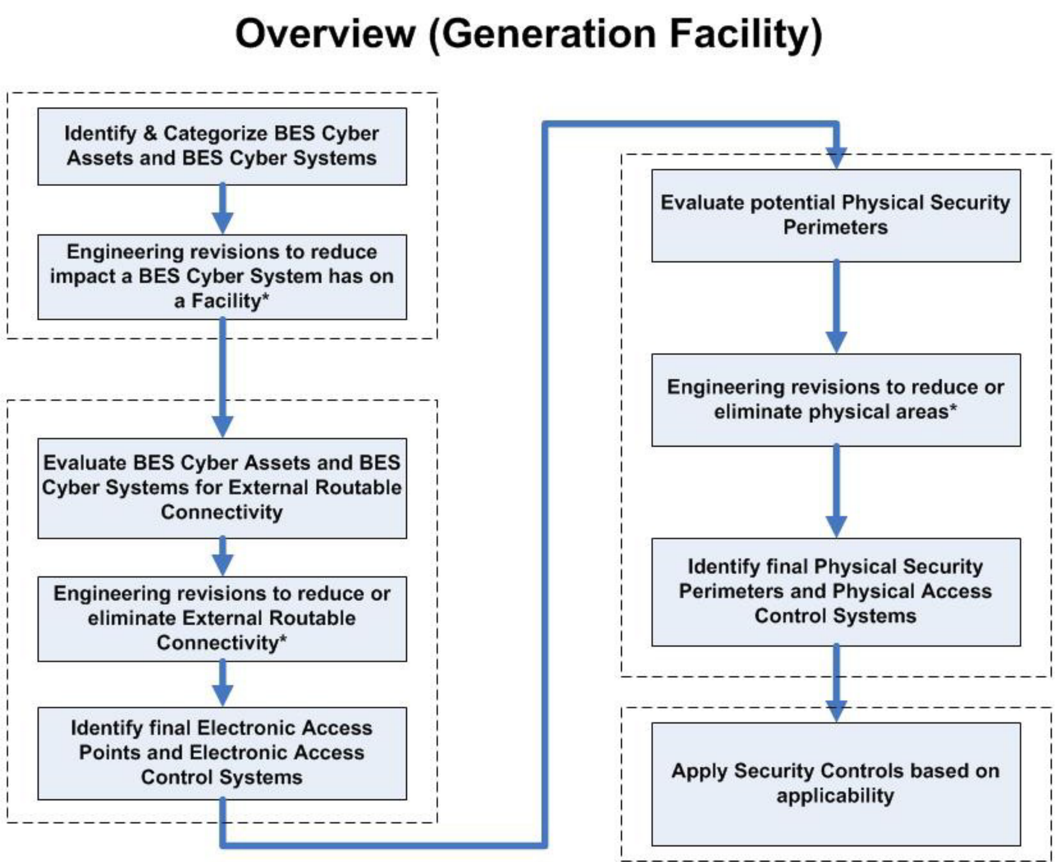
Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.



* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

Rationale

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

Rationale for R1:
BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:
The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement
<u>CIP-002-5.1, Requirement R1</u> R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3: i. Control Centers and backup Control Centers; ii. Transmission stations and substations; iii. Generation resources; iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements; v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above. 1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset; 1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and 1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required). <u>Attachment 1, Criterion 2.1</u> 2. Medium Impact Rating (M) Each BES Cyber System, not included in Section 1 above, associated with any of the following: 2.1 Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.
Questions
Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems." The Interpretation Drafting Team identified the following questions in the RFI: 1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2..." Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*...associated with any of the following [criteria]." (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:

> The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

> Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2021-03 CIP-002

Formal Comment Period Open through November 9, 2023
Ballot Pools Forming through October 25, 2023

Now Available

A formal comment period for **CIP-002-Y — Cyber Security — BES Cyber System Categorization**, is open through **8 p.m. Eastern, Thursday, November 9, 2023**.

There are currently two drafting teams working on modifications to CIP-002-5.1a. The Project 2021-03 standard drafting team (SDT) is posting modifications as CIP-002-Y to differentiate its work from Project 2016-02 Modifications to CIP Standards (CIP-002-7).

Commenting

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

Reminder Regarding Corporate RBB Memberships

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

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Wednesday, October 25, 2023.** Registered Ballot Body members can join the ballot pools here.

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

Next Steps
Initial ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted October 31 – November 9, 2023.

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

For more information or assistance, contact 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 2021-03 CIP-002” in the Description Box.

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

Comment Report

Project Name:	2021-03 CIP-002 | Draft 1
Comment Period Start Date:	9/26/2023
Comment Period End Date:	11/9/2023
Associated Ballots:	2021-03 CIP-002 CIP-002-Y IN 1 ST 2021-03 CIP-002 Implementation Plan IN 1 OT

There were 78 sets of responses, including comments from approximately 172 different people from approximately 111 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT has modified the Control Center definition based on ambiguity that surfaced during the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

2. The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". This was intentional, to make clear that the BES Cyber Systems to consider differ between Control Centers and other assets such as Transmission stations and Generation resources. In alignment with Part 1 of Attachment 1, BES Cyber Systems 'used by and located at' Control Centers need to be considered. This prevents expanding from Control Centers down into field assets. With respect to other assets, it is BES Cyber Systems 'associated with' the assets that are considered. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

3. The SDT revised CIP-002-Y Attachment 1 Criterion 2.12 based on data obtained from the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

4. 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
					Jaimin Patal	Saskatchewan Power Corporation (SPC)	1	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Marc Gomez	Southwestern Power Administration (SWPA)	1	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Bryan Sherrow	Board Of	1	MRO

						Public Utilities (BPU)		
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Michael Ayotte	ITC Holdings	1	MRO
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	TVA RBB	Ian Grant	Tennessee Valley Authority	3	SERC
					David Plumb	Tennessee Valley Authority	1	SERC
					Armando Rodriguez	Tennessee Valley Authority	6	SERC
					Nehtisha Rollis	Tennessee Valley Authority	5	SERC
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
Austin Energy	Imane Mrini	6		Austin Energy	Imane Mrini	Austin Energy	6	Texas RE
					Michael Dillard	Austin Energy	5	Texas RE
					Lovita Griffin	Austin Energy	3	Texas RE
					Tony Hua	Austin Energy	4	Texas RE
					Thomas Standifur	Austin Energy	1	Texas RE
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	4	WECC

						Public Utilities (Tacoma, WA)		
					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
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Ryan Strom	Buckeye Power, Inc	4	RF
					Jim Davis	East Kentucky Power Cooperative	1,3	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
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

California ISO	Monika Montez	2	WECC	ISO/RTO Council Standards Review Committee (SRC)	Monika Montez	CAISO	2	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kathleen Goodman	ISO-NE	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
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
					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	4	NPCC

						Services		
					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
Western Electricity	Steven Rueckert	10		WECC CIP	Steve Rueckert	WECC	10	WECC
					Morgan King	WECC	10	WECC

Coordinating Council					Deb McEndaffer	WECC	10	WECC
					Tom Williams	WECC	10	WECC

1. The SDT has modified the Control Center definition based on ambiguity that surfaced during the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	No
Document Name	

Comment

The description is wordy, is a run-on sentence, and preserves the existing ambiguity regarding what "monitor and control" is in the context of real-time. Our TO organization has an agreement with a third party to "monitor" our limited assets. Many small TO utilities do not "monitor and control in real-time". Monitoring is passive and after-the-fact, not real-time. TO's do not "operate", according to NERC functional definitions, and thus cannot have "operating personnel". We recognize there are larger TO's who have massive Control Centers, and by definition they do "monitor and operate" and should be registered as TOPs. Furthermore, smaller entities like us may have the ability to select a device and open it or close it, but it is only if we are directed to act by our TOP or RC through our agreements. This is not real-time because we do not monitor the overall BES and are not aware of the overall impacts of the operation. Any operation we do is clearly limited, and it is approved ahead-of-time for maintenance and testing purposes, unless otherwise directed. This, in our interpretation, is not real-time operation. Our staff's focus is monitoring and operating a distribution system, the inclusion of our facilities in the definition of a "Control Center" over states what our staff does, and it leads us to believe that NERC System Operator Certification may be required for anyone who may electronically switch their 100kV assets for working on their own distribution system.

A second concern is that smaller generators may use two separate and distinct systems to manage two separate generation facilities from a common room. Furthermore, generation Facilities may be geographically separated, or in the same local area. Bullet #5 doesn't distinguish between NERC registered generation and other small generation. We feel the inclusion of a 980Kw generator in a larger 88Mw facility could be interpreted to be two generation Facilities operated from the same location, thereby making this a Control Center under the new definition.

Overall, it is our feeling that bullets 4 and 5 should not be included, and that this definition should focus on BAs, RCs, and TOPs. The lead in language should be amended to state:

"Control Center - One or more facilities where an RC, BA or TOP hosts NERC Certified operating personnel to monitor and control the Bulk Electric System (BES) in real-time, as described below, including location of the associated Cyber Assets used by to monitor and control the BES in real-time. "

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

Initially, we felt the SAR only allowed for modification to the definition of Control Center as it relates to TO's only. After meeting and talking with the SDT, during their recent webinar, we feel that changing the definition of Control Center for TOs, RCs, BAs, and GOPs, collectively, is allowed, and is appropriate. However, it would not be acceptable to us if the SDT proposed changing the definition for TOs, RCs, and/or BAs, collectively, but excluded

GOPs.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

The standard drafting team has done an excellent job in clarifying a complex definition. The use of one definition for both the control room and associated data center is effective and clear.

There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center, however the generators are individual Facilities and are located over a large physical area.

The following definition is proposed:

4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or

5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.

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 standard drafting team has done an excellent job in clarifying a complex definition. The use of one definition for both the control room and associated data center is effective and clear.

There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center, however the generators are individual Facilities and are located over a large physical area.

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5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Buckeye supports the comments made by ACES:

ACES suggests changing “Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units” to “Field assets, such as remote terminal units, are excluded from the scope of the Control Center’s definition” to avoid ambiguity.

Likes 0	
Dislikes 0	

Response

Paul Mehlhaff - Sunflower Electric Power Corporation - 1

Answer	No
Document Name	

Comment

Sunflower does not believe a modification to the Control Center definition is required.

Likes 0	

Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	

Tacoma Power appreciates the revisions made by the SDT based on the previous informal comment period. Tacoma Power agrees with many of the changes made to the Control Center definition. However, the Control Center definition is still ambiguous on exactly what Cyber Assets are intended to be included. For example, is the intent to include control panels used by operating personnel, the energy management system or the entire system including servers and communication gear?

Tacoma Power recommends additional changes to provide clarity, as follows. Instead of referring to Cyber Assets, the definition should refer to BES Cyber Systems, as this would capture the associated data centers. This change would leverage existing NERC Glossary of Terms to reduce the ambiguity.

Proposed change: “including any spaces that house the **BES** Cyber **System** used by operating personnel to monitor and control the BES in real-time."

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
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”

Comments: While EEI supports the inclusion of BES into the purpose statement, we do not support replacing the defined term “Facility” with the undefined term “resource”. This change does not add any improved clarity and the term Facility should be restored in the Purpose statement.

Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	

Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI’s proposed alternative of not changing the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	

Comment	
The use of one definition for both the control room and associated data center is effective and clear. There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center, however the generators are individual Facilities and are located over a large physical area. The following definition is proposed: 4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or 5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
From the Technical Rationale "The phrase “any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time” was developed to replace “associated data center”. Do the spaces located in a room that does not house operating personnel, but is in the same building as a room that houses operating personnel (shared street address) and the spaces located in a separate building from any rooms that house operating personnel get classified as Control Centers? These spaces were known as “associated data centers” and were not included in the count of Control Centers. Clarifying language is needed in the definition that states if the rooms, that do not physically host operating personnel, are not classified as Control Centers. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No

Document Name	
Comment	

The proposed changes are too specific to the architecture of the building and does not provide clarity on what is meant by “hosting”.

For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

{C}1) If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers but no one is assigned to that desk, is the engineering office a Control Center? or

{C}2) If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or

{C}3) If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or

{C}4) If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center?

{C}5) If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a

Control Center?

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

AEPC signed on to ACES comments below:

ACES suggests changing “Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units” to “Field assets, such as remote terminal units, are excluded from the scope of the Control Center’s definition” to avoid ambiguity.

Likes 0	
Dislikes 0	
Response	

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	No
Document Name	
Comment	
LCRA believes the changing of the definition of Control Center is outside of the scope of the SAR and has unintended consequences to other standards.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports NAGF's comments on this project	
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	
ACES suggests changing “Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units” to “Field assets, such as remote terminal units, are excluded from the scope of the Control Center’s definition” to avoid ambiguity.	
Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA believes the changing of the definition of Control Center is outside of the scope of the SAR and has unintended consequences to other standards.	
Likes 0	
Dislikes 0	
Response	

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	
PNMR (TNMP and PNM) agrees with EEI Comments. Specifically, we support the alternative recommendation to create a new defined term for TOCC. PNMR agrees with leaving the existing definition of Control Center since it is in several other CIP and O&P requirements. We believe changing the definition would require a SAR to change the definition or modify the standards that use the definition. Instead, the SDT should create a new definition Transmission Owner Control Center that is only used in CIP-002 as the NERC Rules of Operating Procedure doesn't recognize Transmission Owners having responsibilities associated with a control center. This avoids adversely affecting a definition a majority do not have a problem with and allow the SDT to scope in Transmission Owner Control Centers in CIP-002 which is the only place it comes up because of a FERC order	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	No
Document Name	
Comment	
While WECC recognizes the need for the SDT to provide clarity to this complex definition, some of the modifications to the Control Center definition appear to have also created unintended consequences as well. In the context of Associated Data Center - "A space that houses Cyber Assets used by operating personnel to monitor and control the BES in real-time may be: • located in the same room that houses operating personnel."	

This proposed revision appears to bring a home office where personnel using a Cyber Asset with Interact Remote Access (IRA) to monitor and control the BES in real-time into scope as a Control Center.

In the context of IRA, the standards have not brought in the remote Cyber Asset into scope as any applicable system of the standards, but the first bullet appears to bring a home office into scope as a Control Center and Cyber Asset with this capability into scope as a BCA.

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 drafting team's efforts and the opportunity to comment, and provides the following.

Proposed modifications to the definition of Control Centre don't align with CIP-002.5.1a Attachment 1 high and medium impact Control Center criteria 1.1 to 1.4 and 2.11 to 2.13 as these Control Centre criteria still use "perform functional obligations" language which is equivalent to "to perform the reliability tasks" SDT tried to replace. For instance, in a GOP control room, the operating personnel are capable of controlling generating units at two generation plants, but they don't perform GOP obligations that are only taken by the GOP System Operators. Even though this GOP control room would become a Control Centre based on the modified Control Centre definition, it wouldn't meet any high or medium Control Center impact rating criteria thus only becoming a low impact Control Center.

The language around "the capability to electronically control Transmission Facilities at two or more locations has a Control Center" is vague and could encompass facilities and locations that definitely should not be considered control centers.

The SDT is requested to consider not removing 'reliability-related tasks' from the currently defined terms as this will further clarify who is 'operating personnel'.

BCH also seeks clarity on the use of the word 'capability'. SDT should allow for provisions where protections have been implemented that reduce/impair 'capability', but there still exists the possibility without those protections.

The inclusion of points 4 and 5 (in Control Center Definition) for consideration of operating personnel (i.e. technicians and electricians may qualify) would effectively turn any generation control room that has the capability to electronically control a local and remote BES asset into a Control Center.

BC Hydro suggest that SDT provide some use cases and examples to clarify this, and makes the following recommendations:

1) Modify CIP-002 Attachment 1 criteria 1.1 to 1.4 and 2.11 to 2.13 to change "perform functional obligations" to "control Facilities".

2) Provide clarity of the use term 'operating personnel' in item 4 and 5 of Control Center definition and use of the term 'capability' with use cases and examples.

3) In the Control Center definition suggest changing the points 1 or 2 or 3 or 4 or 5 to: 1 or 2 or 3 or (1 or 2 or 3 and 4) or (1 or 2 or 3 and 5). This will ensure that Real-time monitoring and control of the BES is occurring, instead of including in the Control Center definition control rooms only performing local load control.

Likes 0	

Dislikes 0	

Response

Thomas Standifur - Austin Energy - 1	
Answer	No
Document Name	

Comment

Austin Energy believes the proposed change to the definition of Control Center is too broad and vague with the inclusion of “any spaces that house”. In addition, a change to this core definition could have cascading impacts to other NERC standards and introduce potential conflict and confusion. In addition, the SAR does not include/request a definition change.

Likes 1	Austin Energy, 6, Mrini Imane
Dislikes 0	

Response

Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	No
Document Name	

Comment

The proposed change to the definition of Control Center is too broad and vague with the inclusion of “any spaces that house”. In addition, a change to this core definition could have cascading impacts to other NERC standards and introduce potential conflict and confusion. In addition, the SAR does not include/request a definition change.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments and recommends the changes proposed for the definition by EEI.

Likes 0	

Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's comments which state:

EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface):

Control Center - One or more **facilities** where a responsible entity **houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **Cyber Assets BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **located** in a centralized location and exclude field assets such as remote terminal units.

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations;

4. Transmission Owner **facilities who that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or

5. Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for** generation Facilities at two or more **separate physical** locations.

Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
From the Technical Rationale "The phrase “any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time” was developed to replace “associated data center”. Do the spaces located in a room that does not house operating personnel, but is in the same building as a room that houses operating personnel (shared street address) and the spaces located in a separate building from any rooms that house operating personnel get classified as Control Centers? These spaces were known as “associated data centers” and were not included in the count of Control Centers. Clarifying language is needed in the definition that states if the rooms, that do not physically host operating personnel, are not classified as Control Centers. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	No
Document Name	
Comment	

AEP supports the comments made by EEI. Specifically:

EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface):

Control Center - One or more **facilities** where a responsible entity **houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **located** in a centralized location and exclude field assets such as remote terminal units.

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations;

4. Transmission Owner **facilities who that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or

5. Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for** generation Facilities at two or more **separate physical** locations

Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition.

Kent Feliks on behalf of AEP in Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	No
Document Name	

Comment

Exelon is responding in support of EEI's response to this question.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

NEE supports EEI's comments: "EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface):

Control Center - One or more **facilities rooms** where a responsible entity **hosts houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **any spaces that house the Cyber Assets BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **Cyber Assets BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **housed located** in a centralized location and exclude field assets such as remote terminal units.

Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations;

. **Operating personnel of a** Transmission Owner **facilities who that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or

Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for who have the capability to electronically control** generation Facilities at two or more **separate physical** locations; **in real-time**.

Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Southern Company agrees with the comments from 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 comments of the MRO NSRF.

Additionally, we support the following comment proffered by EEI:

"Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition."	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS does not agree with the proposed changes but does supports the comments that were submitted by EEI on behalf of their members to improve the definition for Control Centers. Either by incorporating their proposed submitted changes or by their submitted suggestion of creating a CIP-002 specific definition for Control Centers targeting TO Control Centers.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.

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 Insititute (EEI) for question #1.

Likes 0	
Dislikes 0	

Response
Alain Mukama - Hydro One Networks, Inc. - 1

Answer	No
Document Name	

Comment
Suggest to change to “One or more designated rooms or buildings…” in order to avoid calling any area including remote locations where operating personnel may monitor and/or control remotely with their approved cyber assets, such as engineering workstation. Suggest to define operating personnel so that the role is only active inside Control Center (i.e. remote monitoring and controlling outside of Control Center not allowed)

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 notes that the field test did not include REs from the other functional models impacted by the proposed changes. Therefore, the NAGF recommends preserving the current Control Center definition language and incorporating additional language to directly address the Transmission Owner risk(s). This approach will avoid unintended consequences such as the potential expansion of in scope Cyber Assets applicable under the revised language addressing data centers.	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	

Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface):

Control Center - One or more **facilities** where a responsible entity **houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **located** in a centralized location and exclude field assets such as remote terminal units.

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;
3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations;
4. Transmission Owner **facilities that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or
5. Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for** generation Facilities at two or more **separate physical** locations.

Likes 0	
Dislikes 0	

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer	No
Document Name	

Comment

NST disagrees with the proposed changes to the definition of "Control Center" for the following reasons:

> NST has helped a multitude of Registered Entities achieve and maintain compliance with the CIP Standards, beginning with Version 1, and we have yet to interact with one whose Subject Matter Experts were unclear about the meaning of "facility" in the Control Center definition that became effective July 1, 2016. We have likewise encountered no confusion about what a "data center" is. NST acknowledges the field test report's statement that a number of TOs "have struggled to interpret the Control Center definition," but we also note the approximately 20 TOs that provided information during the study represents a very small percentage of Registered Entities subject to the CIP Standards.

> NST believes the proposed change from "data centers" to "spaces" to connote where a Control Center's Cyber Assets might reside reduces rather than increases clarity. What, exactly, is a "space"?

> The proposed changes fail to address an important question that the advent of requirements applicable to communication links between Control Centers (CIP-012) brought to the fore: Is a data center that houses some of a Control Center's Cyber Assets (e.g., SCADA/EMS servers) itself a Control Center? A CIP-012-1 webinar presented by NERC and the six Regional Entities on June 2, 2022 stated, "A data center is a Control Center." NST considers this assertion to be both incorrect and problematic for several reasons, including the fact that while it's possible for a Control Center's operators and the servers they use to be in different Zip Codes, it's also entirely possible for the operators and all the Cyber Assets they need to be in the same room of the same building. Are there TWO Control Centers in the latter instance? Of course not.

NST believes it is essential that this issue be addressed by any attempt to update the current definition of Control Center, and we respectfully submit the following alternate language for the SDT's consideration:

A Bulk Electric System asset used by the operating personnel listed below to monitor and control the Bulk Electric System in real-time. A Control Center includes:
- Workspaces for operating personnel
- Cyber Assets used by operating personnel to monitor and control the BES in real-time. Some of those Cyber Assets may be, in some instances, in a different physical location (e.g., a remote data center) than the operator workspaces

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more

locations;

4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or

5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more locations in real-time.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC/RSC's comments.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

The standard drafting team has done an excellent job in clarifying a complex definition. The use of one definition for both the control room and associated data center is effective and clear.

There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center; however the generators are individual Facilities and are located over a large physical area.

The following definition is proposed:

4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or

5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.

Likes 0	
Dislikes 0	

Response

Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The ISO/RTO Council (IRC) Standards Review Committee (SRC) is concerned that the phrase "electronically control . . ." in paragraphs 4 and 5 of the proposed Control Center definition does not achieve the purpose described in the Technical Rationale of differentiating between remote control in Real-time and control via instructions issued to field personnel. Specifically, the SRC is concerned that the term "electronically" could cause confusion, as the radios or telephones used to issue instructions to field personnel could be viewed as an electronic form of control, while Real-time control that relies on mechanical or fiber optic means of control might be considered to fall outside the bounds of electronic control.

The SRC proposes that the drafting team consider removing the word "electronically" from paragraphs 4 and 5. The SRC believes that the qualifier "in real-time" at the end of each paragraph should suffice to achieve the goal described in the Technical Rationale. Dispatching field personnel to a location to perform an action would arguably not count as Real-time control, since time would elapse between the issuance and the execution of an instruction while the field personnel travel to the location and execute the actions needed to control the impacted Facility. On the other hand, a scenario in which instructions are being conveyed via radio or telephone to field personnel who are already on-site at a Facility and will execute the instructions within seconds of receiving them might be considered Real-time control, but this may be consistent with the overall purpose of the Control Center definition.

Additionally, the SRC notes that the proposed definition alternates between using the capitalized term "Real-time," which is defined in the NERC Glossary of Terms, and the uncapitalized term "real-time." The SRC requests that the drafting team adopt a consistent capitalization approach to clarify whether the definition from the NERC Glossary of Terms is intended to apply. If the NERC Glossary definition is not intended to apply, or if it is only intended to apply in some locations, the SRC requests that the drafting team use a different term in place of the uncapitalized term "real-time" to avoid confusion with the capitalized term defined in the NERC Glossary.

Finally, in order to provide further clarity, the SRC suggests that the first two sentences of the definition of a Control Center be revised and combined into a single sentence that reads as follows:

Control Center: One or more rooms where a responsible entity hosts any of the operating personnel described in paragraphs 1-5 below who monitor and control or monitor and direct action for the Bulk Electric System (BES) in Real-time, and any spaces that house the Cyber Assets used by operating personnel to monitor and control or monitor and direct action for the BES in Real-time, excluding field assets such as remote terminal units.

Likes 0	
Dislikes 0	

Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The standard drafting team has done an excellent job in clarifying a complex definition. The use of one definition for both the control room and associated data center is effective and clear. There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center, however the generators are individual Facilities and are located over a large physical area.	

The following definition is proposed:

4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or

5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.

Likes 0	
Dislikes 0	

Response

Megan Melham - Decatur Energy Center LLC - 5

Answer	No
Document Name	

Comment

The field test was only conducted and directed at Transmission Operators and Transmission Owners and doesn't consider the impact to registered entities outside of this range. Recommend preserving the previous language and adding additional language to address the Transmission Owner risk(s). Additionally, the expanded wording used to address "data centers" could have unintended consequences such as the potential expansion in scope of applicable Cyber Assets and rooms. An example of excluded field assets is given as the remote terminal units; it's unclear if protection relays and the communication equipment used to provide real-time information to the operating personnel would also fit under this exclusion.

Likes 0	
Dislikes 0	

Response

Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No
Document Name	

Comment

Duke Energy supports NAGF comments on the Control Center definition and appreciates the work of the Drafting Team, including all the industry engagment through the previous informal comment period. Duke Energy also support's EEI's comments on the concerns regarding scope expansion in the draft language for GOPs. If the Drafting Teams feels that the "associated data center piece" must be expanded on , and that they cannot keep the body of the current definition as NAGF suggests, Duke Energy suggests the following alternative language:

One or more facilities where a responsible entity houses operating personnel who perform the functional entity obligations described below, including locations that contain BES Cyber Systems used by those operating personnel to support the functional entity's capability to monitor and have control authority of the Bulk Electric System (BES) in Real-time.

1.Reliability-related tasks of a Reliability Coordinator,

2. Reliability related tasks of a Balancing Authority,

3. Reliability-related tasks of a Transmission Operator at two or more locations,

4. Reliability-related tasks of a Transmission Owner at two or more locations,

5.Generator Operator having the capability to electronically control generation Facilities at two or more locations.

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	Yes
Document Name	

Comment

The current proposed definition of Control Center is very wordy. Consider creating a separate definition of data center leveraging the wording in the current proposed definition of Control Center. This may allow for better overall readability.

Likes 0	
Dislikes 0	

Response

Tracy MacNicoll - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

The drafting team should clarify the last sentence of the core definition. Are field assets such as remote terminal units excluded from the Control Center definition? “Real-time” in 4 and 5 should be capitalized.

Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
While we can agree with the proposed changes we do have a couple suggestions. The last sentence of the proposed first paragraph is "Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units." 1. It's not obvious to us the purpose of the words "are generally housed in a centralized location and". Could they be deleted? Also, the term "field assets" is used in that sentence. 2. The October 30th webinar conducted by the SDT included "data aggregators" as a type of field asset. Because of their common use, we recommend adding data aggregators alongside remote terminal units in that text.	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scot Nairn - Bonneville Power Administration - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - 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	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	
Document Name	

Comment

Please see comments by Marty Hostler, NCPA. Thanks.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE is concerned the proposed definition of Control Center inherently scopes Control Center's down from a "location" (facilities) perspective to a "room" perspective. This could be problematic for other CIP and O&P standards such as CIP-014-2 and TOP-001-5. Texas RE recommends the definition clarify that the entire applicable facility is included, rather than simply one space within the facility. For example, if the proposed definition were adopted, in CIP-014-2, only the Control Center "room" would need to be evaluated for potential threats and vulnerabilities of a physical attack. This leaves out other areas of that facility which should also be afforded the protections of CIP-014-2. As a second example, if the proposed definition were adopted, in TOP-001-5, only the Control Center "room" would need to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure, which leaves out other areas of the facility that should have data exchange capabilities, such as the data center.	
Likes 0	
Dislikes 0	
Response	

2. The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: “Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:”. This was intentional, to make clear that the BES Cyber Systems to consider differ between Control Centers and other assets such as Transmission stations and Generation resources. In alignment with Part 1 of Attachment 1, BES Cyber Systems ‘used by and located at’ Control Centers need to be considered. This prevents expanding from Control Centers down into field assets. With respect to other assets, it is BES Cyber Systems ‘associated with’ the assets that are considered. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
The proposed language does not provide additional clarification. The statement above Criteria 2.11, 2.12, and 2.13 is already at the top of Section 2 above Criteria 2.1 and is redundant with verbiage already included in each of the three criteria where it states “…that is not already included in High Impact Rating (H) above…”. Recommend removing the preface and leaving Criteria 2.11, 2.12, and 2.13 as written.	
Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
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 recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language	

prefacing section 2.11, 2.12, and 2.13: “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above,”.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
The initial scope of the 2021-03 SAR initially authorized changes to 2.12, and 2.11 and 2.13 were subsequently added.	

The added sentence after Criterion 2.10 does not seem to add value since there the Section 2 Medium Impact Rating already includes the "associated with" wording. We understand that the intention is to group the Control Centers from other assets. BC Hydro suggests organizing the Attachment 1 by groups to clarify the scope and application.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports NAGF's comments on this project	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. "Each Control Center or backup Control Center, not already included in High Impact Rating (H) above".	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	

Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
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” Comments: In the project SAR, bullet 1 under the Project Scope section, the SDT was asked to “[c]larify VAR-002-4.1 Requirement R3 in regards to whether the GOP of a dispersed power resource must notify its associated TOP of a status change of a voltage controlling device on an individual generating unit, for example if a single inverter goes offline in a solar PV resource.” This change was recommended to provide uniformity between wind turbine plants with other dispersed power producing resources. We support this change and recommend the SDT include a similar reporting exception for Requirement R3 to what exists in VAR-002-4.1, Requirement R4 as proposed in both the supporting white paper for this project and the Project SAR. EEI also asked the SDT to remove proposed Requirement R3 language that states “in a mutually-agreed communications method”, because this language serves no reliability benefits but adds unnecessary compliance obligations; i.e., the need to document that an agreement was developed, mutually agreed to and was followed.	
Likes 0	

Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Instead of grouping Criteria 2.11, 2.12 and 2.13 in Section 2, Tacoma Power recommends creating a new Section in CIP-002 to house these criteria. If the intent of the SDT is to have these three criteria grouped separately from the other medium impact criteria in Section 2, grouping would be served better by creating a new separate section.	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Sunflower votes no due to our disagreement with making modifications to the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
We agree with the proposed preface to Criteria 2.11, 2.12, and 2.13, however feel some additions need to be made to clarify “used to perform the functional obligation of” throughout the Attachment 1 criteria. The SAR on page 3, indicates that the language scope "perform the functional obligation of" needs clarification throughout the Attachment 1 criteria, not	

just IRC 2.12.

In IRC 2.11 clarification is needed for "used to perform the functional obligation". In a FERC 2017 Audit lessons learned document, which auditors have referenced, during past audits and conferences/webinars, it claims that non-BES assets are to be included in the aggregate net real power calculation. This puzzles us and others as it is unclear to how a GOP performs functional obligations for non-registered non-BES generators, which have no NERC GOP functional obligations.

The IRC 2.11 clearly states to us that you aggregate the net real power of generators for which the GOP performs functional obligations. Since non-BES generators have no functional obligations they are not to be included.

Regardless, we include non-BES generation in our IRC 2.11 calculations, even though we do not believe it is required to do so, simply because auditors have told us that we have to, based on the aforementioned 2017 FERC Audit Lessons Learned document.

We suggest that the following language be added in the aforementioned proposed preface language or at the end of IRC 2.11. "Only BES generation is to be aggregated when determining the net real power capability, non-BES generation is not to be included".

Or restate, in the aforementioned preface, that GOPs do not perform functional obligations for non-BES assets, and non-BES generation is not to be included when determining a GOPs impact rating in IRC 2.11. We realize that this may seem repetitive and/or intuitive to the SDT but, per the aforementioned 2017 Lessons Learned document, others may not have known the non-BES assets have no functional obligations. And that a GOP is not accountable to perform GOP functional obligations for a non-BES generator that has no GOP functional obligations. Consequently, GOPs do not include non-BES generation when calculating net real power in IRC 2.11.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

EEI supports this proposed change.

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	Yes
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Insititute (EEI) for question #2.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
AZPS agrees with the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the comments from EEI.	

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
NEE supports the change and is in agreement with EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon is responding in support of EEI's response to this question.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Affirmative specifically for Criteria 2.11. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy supports this change.

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

This change helps to group Control Centers from other assets, but ACES suggests grouping Attachment 1 by registration or adding a matrix by registration to make classification easier, particularly with the potential introduction of new NERC registrations, such as IBR.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

AEPC signed on to ACES comments below:

This change helps to group Control Centers from other assets, but ACES suggests grouping Attachment 1 by registration or adding a matrix by registration to make classification easier, particularly with the potential introduction of new NERC registrations, such as IBR.

Likes 0	

Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Affirmative specifically for Criteria 2.11. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Buckeye supports the comments made by ACES: This change helps to group Control Centers from other assets, but ACES suggests grouping Attachment 1 by registration or adding a matrix by registration to make classification easier, particularly with the potential introduction of new NERC registrations, such as IBR.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	

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	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
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	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Standifur - Austin Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
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	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scot Nairn - Bonneville Power Administration - NA - Not Applicable - 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	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
Please see comments by Marty Hostler, NCPA. Thanks.	
Likes 0	
Dislikes 0	
Response	

3. The SDT revised CIP-002-Y Attachment 1 Criterion 2.12 based on data obtained from the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

Yes. the proposal is ok.

Likes 0	
Dislikes 0	

Response

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

The definition of a control center add in #4 “Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;” to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact.

The following wording is suggested for 2.12 to resolve this:

Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

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 definition of a control center add in #4 “Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;” to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact.

The following wording is suggested for 2.12 to resolve this:

Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

The Exclusion language in Criterion 2.12 could effectively allow up to 1499MW of generation to offset any export, especially when that generation is not within the load center. Under the current language entities with a significant aggregate weighted value several times the 6000 limit would be allowed to exclude a local system that has a “net” export less than 75MW if they have generation to offset as a negative export (import). Tacoma Power recommends removing the word “net” from the Exclusion to resolve this issue.

Suggested Exclusion language:

“Exclusion: BES Transmission Lines monitored and controlled by the Control Center or backup Control Center may be excluded from the “aggregate weighted value” calculation if they are part of a local system that is operated at less than 300kV, where the **export** from the local system does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The **export** is based on the hourly integrated values for the most recent 12-month period.”

Likes 2	Snohomish County PUD No. 1, 6, Liang John; LaKenya Vannorman, N/A, Vannorman LaKenya
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" Comments: EEI does not support the deletion of the bulleted reporting exception for individual generating units of dispersed power producing resources made to Requirement R4. The SAR scope asked the SDT to clarify whether a similar exception should be added to Requirement R3, not delete the reporting exception already contained in Requirement R4. Moreover, there is no justification provided for removing this reporting exception. The SDT should restore the bulleted reporting exception for individual generating units of dispersed power producing resources as currently contained in VAR-002-4.1. EEI also asked the SDT to remove proposed Requirement R4 language that states "in a mutually-agreeable communications method", because this language serves no reliability benefits but adds unnecessary compliance obligations; i.e., the need to document that an agreement was developed, mutually agreed to and was followed.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI's comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	

Comment	
Black Hills Corporation is in agreement with EEI’s comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	

Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI’s comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	

The definition of a control center add in #4 “Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;” to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact.

The following wording is suggested for 2.12 to resolve this:

Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

AEPC does not completely agree with the changes. Specifically, because the implementation of the exceptions are non-standard to the CIP-002 inclusion/exclusion process(es).

AEPCs objection is very similar to ACES’ feedback below, but ACES chose to be in favor of the changes because the exception language has no impact to the original weighting from the previously passed CIP-002-6 and gave entities the flexibility to define “local network”.

ACES Feedback: ACES agrees with the changes, but proposes additional clarity. The SDT did a great job with the additional exception from CIP-002-6, but failed to define a “local network”. There is documentation in the technical rationale, but feel we need crystal clear guidance when potentially excluding a BES Transmission Line which potentially make a Control Center medium or low impact.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

Ameren supports EEI's comments on this project

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	
ACES agrees with the changes, but proposes additional clarity. The SDT did a great job with the additional exception from CIP-002-6, but failed to define a “local network”. There is documentation in the technical rationale, but feel we need crystal clear guidance when potentially excluding a BES Transmission Line which potentially make a Control Center medium or low impact. ACES’ Member Arizona G&T Cooperatives (AEPC) does not completely agree with the changes. Specifically, because the implementation of the exceptions are non-standard to the CIP-002 inclusion/exclusion process(es).	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
Based on the feedback provided to Question #1 above and the comments provided during the informal commenting period of this Project 2021-03 CIP-002-Y changes in July 2023. BC Hydro maintains the position that these changes are introducing ambiguities to the Control Center definition and its application, and request to kindly address the comments provided.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE has no objection to the proposed criteria.	
Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI's comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE is in support of the comments as submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon is responding in support of EEI's response to this question.	
Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE supports EEI's comments: The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees with the comments from EEI.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	

Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS does not agree with the proposed changes but does supports the comments that were submitted by EEI on behalf of their members related to the exclusion of transmission lines below 100kv except those that were identified through appendix 5C of the Rules of Procedure as BES Transmission Lines. As currently written there needs to be clarity for criteria for lines below 100kv.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
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 Insititute (EEI) for question #3.	
Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	No
Document Name	
Comment	
NST considers the "Exclusion" language to be insufficiently clear (e.g., What is a "local system"?), and we believe the SDT should endeavor to simplify a requirement that appears to require a set of highly complex calculations.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

The definition of a control center add in #4 "Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;" to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered medium impact.

The following wording is suggested for 2.12 to resolve this:

Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE is concerned that the way of calculating the risk may not cover all scenarios and does not account for differences in Transmission lines. Texas RE has taken the position that that BCS used to perform the functional obligations of a Transmission Operator should remain categorized as medium impact or high impact. The risk the BCS at a Control Center poses to the reliable operation of the BES is not easily covered by counting the quantity of transmission lines operated. Two Control Centers operating the same number of transmission lines may pose very different risks to the BES. For example, if one Control Center is predominantly operating Transmission lines at substations interconnected with Generation Facilities it may pose more risk than a Control Center operating Transmission lines at substations that are not interconnected with Generation Facilities.

Texas RE proposes the following language for criterion 2.12:

Each Control Center or backup Control Center operated by a Transmission Operator or owned by a Transmission Owner.	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The definition of a control center add in #4 “Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;” to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact. The following wording is suggested for 2.12 to resolve this: Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.	
Likes 0	

Dislikes 0	

Response

Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
We support EEI comments on Attachment 1 Criterion 2.12.	
Likes 0	
Dislikes 0	
Response	

Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Buckeye supports the comments made by ACES: ACES agrees with the changes, but proposes additional clarity. The SDT did a great job with the additional exception from CIP-002-6, but failed to define a “local network”. There is documentation in the technical rationale, but feel we need crystal clear guidance when potentially excluding a BES Transmission Line which potentially make a Control Center medium or low impact.	
Likes 0	

Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
We do not support EEI comments. Exclusions are built into the BES definition. The table used to calculated weighted value imposes the definition in the table header.	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Use of the undefined term “backup” Control Center is unnecessary, versus simply utilizing the defined term "Control Center.” For clarification, for 500kV and above, add the text “automatic high impact” rather than stating “0”.	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Owens - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scot Nairn - Bonneville Power Administration - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Standifur - Austin Energy - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

John Daho - MEAG Power - 1,3 - SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
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	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	

Answer	
Document Name	

Comment

Constellation has no comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	
Document Name	

Comment

Please see comments by Marty Hostler, NCPA. Thanks.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group has comment on Attachment 1 Criterion 2.12 as it specifically applies to TO/TOP functions/registrations	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no comment as Criterion 2.12 applies specifically to TO/TOP registrations.	
Likes 0	
Dislikes 0	
Response	

4. Provide any additional comments for the SDT to consider, if desired.

Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	
The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months, or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come into effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This	

would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports NPCC/RSC's comments.

Likes 0	
Dislikes 0	

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer	
Document Name	

Comment

(No further comment)

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 is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	

Response

Alain Mukama - Hydro One Networks, Inc. - 1

Answer	
Document Name	

Comment

Request clarification of "BES Transmission Line". "BES" is defined as Transmission elements operated at 100 kV or higher, so "BES Transmission Line" is expected to be Transmission Lines operated at 100 kV or higher. However, the new 2.12 includes weight value below 100 kV. Please define or explain.

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 MRO NSRF for question #4.

Likes 0	
Dislikes 0	

Response

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	
Document Name	

Comment

A negative vote was cast in error. We support the changes.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	
Document Name	

Comment

WEC Energy Group supports the following comment drafted by the NAGF:

"The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities."

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Kent Feliks - AEP - 3

Answer	
Document Name	

Comment

Understanding of the proposed revisions would be greatly enhanced by providing Implementation Guidance.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no additional comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	
Document Name	

Comment

Black Hills Corporation is in agreement with NAGF comments: "The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities."

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro recognizes the effort done by this drafting team to encapsulate the changes via Project 2021-3 CIP-002-Y and look forward to the resolution of the comments and suggestions provided.

Additionally with respect to the Implementation Plan there are multiple time frames allowed for the implementation period per the new changes to CIP-002-Y standard e.g., 12 months for net new BCS (high/medium) and 24 months for entities first time identified high or medium impact BCS.

BC Hydro recommends that in all cases including a net new high/medium impact BCS, newly categorized high impact BCS from medium impact BCS and newly categorized medium impact BCS implementation time should be a minimum of 24 months.

For instance, in cases where existing assets are newly identified as Control Centres as a result of the new Glossary and CIP-002 standard revisions which in turn results in the identification of newly categorized high impact BCS from medium impact BCS and newly categorized medium impact BCS BES Cyber Systems there should be a minimum of 24 months to comply with the breadth of applicable CIP standards. This would not be limited to only those cases that meet criterion 2.12 but other impact rating criterion explicitly associated with Control Centre BES Cyber Assets (e.g. high impact rating criterion 1.1 through 1.4, other medium impact rating criterion, and low impact rating criterion).

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	
Document Name	

Comment

Please see comments by Marty Hostler, NCPA. Thanks.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	
Document Name	
Comment	
No additioinal comments.	
Likes 0	
Dislikes 0	
Response	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
LCRA believes that changing the definition of Control Center will have unintended consequences. This change impacts the applicability of CIP-012 and may impact additional Operations and Planning Standards.	
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	
ACES would like to thank the SDT for its continued hard work.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren supports NAGF's comments on this project	
Likes 0	
Dislikes 0	
Response	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	
Document Name	
Comment	
LCRA believes that changing the definition of Control Center will have unintended consequences. This change impacts the applicability of CIP-012 and may impact additional Operations and Planning Standards.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	

AEPC appreciates the opportunity to comment and appreciates the hard work by the SDT.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
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	
Suggest that guidance be given on the result of combining the “BES” and the “Transmission Line” NERC defined terms. While the BES term allows for Transmission lines less than 100kV the “Transmission Lines” sets a lower limit of 69kV. Request clarification for a 69 kV line that meets the Transmission Line definition but not the BES definition. This is not specific to this question and may identify an issue that is not technically possible but there is a gap between the X99 and Y00 “Characteristics of Line” levels. A 199.5kV line is not rated on this table. Request explicit explanation (in the Standard) of the weighted value of zero for “Each BES Transmission Line 500 kV and above.” (see Criterion 2.5) We agree with the weighted value. Please correct as needed – we understand that a Control Center with such a Tranmission Line is High Impact. The language for the exemption seems to allow for the exclusion of a Controls Center as Medium impact if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines, even if these lines are not tied together within the Transmission system controlled by the Control Center.	

Does the “net” in “net export” apply to the net total for all applicable BES Transmission Lines at a single point in time or the net export of each of these lines over the 12 month period.

The 12 month period portion of the language makes it unclear how new transmission lines are handled even if it is known that they will increase the “net export” beyond the 75MW threshold.

The SDT should provide clarity on if a change in the “net export” fluctuates around or exceeds for the first time, the 75MW threshold. When is exceeding the threshold an “unplanned change”, allowing for a 2 year implementation and when is it a “planned change” requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center looses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then looses the exemption, if there are not other medium impact programs in place, do they always get 2 year to either implement the plan or pray that they gain the exemption before the implementation period is over?

Likes 0	
Dislikes 0	

Response

Tracy MacNicoll - Utility Services, Inc. - 4

Answer	
Document Name	

Comment

The way **“Phased-in Implementation Date for CIP-002-Y, Requirement R1, Attachment 1 Criterion 2.12”** in the implementation plan is currently written, entities may have between 9 and 24 months following their first CIP-002-Y assessment to implement a higher impact level categorized BES Cyber System. This is due to the fact that they can perform their initial assessment up to 15 months following the Effective Date of CIP-002-Y based on when they performed their previous assessment. The drafting team should consider starting the 24-month clock once an entity performs its initial CIP-002-Y assessment, not based on the effective date of CIP-002-Y as it is currently written.

Entities that identify their first high impact or medium impact BES Cyber System, under their initial CIP-002-Y assessment, should be awarded the full 24 month compliance implementation per the last row of the table on page 4 of 5 of the Implementation Plan regardless of if they perform that assessment 1 month or 14 months following the Effective Date of CIP-002-Y.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	

Document Name	
Comment	

Constellation has no comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Karen Artola - CPS Energy - 1,3,5 - Texas RE

Answer	
Document Name	
Comment	

Please provide clarification on the intent of the retirement of Sections in CIP-002-5.1a labeled “Background” and “Guidelines and Technical Basis” from the CIP-002-Y proposed draft language to the Technical Rationale Project 2021-03 CIP-002 | Reliability Standard CIP-002-Y document. Especially of concern is the retirement of the concept of BES reliability operating service (BROS) from the CIP-002 Cyber Security-BES Cyber System Categorization standard entirely. The BROS is essential for the proper classification/categorization of BES Cyber Systems (BCS) and in determining the overall BES impact of those BCS. The ongoing use of the BROS in BCS categorization and BES impact rating determination may have been overlooked by the Project 2021-03 CIP-002 SDT based on the statement: "...to preserve any historical references."

Likes 0	
Dislikes 0	
Response	

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	
Comment	

The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	
Document Name	

Comment

Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.”

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	
Document Name	

Comment

Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.”

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	
Document Name	

Comment

Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may

increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.”	
Likes 0	
Dislikes 0	
Response	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	
Document Name	
Comment	
Under the definition of a control center, please define or clarify what is consider “in real-time". Is real-time considered within 15 minutes impact, 5 minutes, or immediate?	
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” While EEI does not oppose the use of the term “generator resource(s)” in place of generator, it does not add any enhanced clarity to the language of the VAR-002, noting that the term generator is well understood in the industry.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	
Document Name	
Comment	

Thank you for the opportunity to comment.

Likes 0

Dislikes 0

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer

Document Name

Comment

The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO

Answer

Document Name

Comment

The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 0

Dislikes 0

Response

Marty Hostler - Northern California Power Agency - 4

Answer	
Document Name	
Comment	

The SAR indicates to clarify "perform the functional obligation of " throughout the Attachment 1 criteria. See proposed clarifications in response 2 above.

If the SDT is not willing to make said clarification changes then please inform us where NERC specifically lists functional obligations associated with non-registered non-BES generation. The standard we believe already clearly states BES throughout it, but oblivious some auditors have made an interpretation that we are being subject to, and should not be subject to.

Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	
Document Name	
Comment	

This standard will burden smaller utilities (TOs) who have minimal transmission assets but who will be required to assess their system annually (every 15 months) to show their newly defined Control Centers will fall under the mathematical threshold of applicability. It will also create a path where the new definition of a Control Center may risk the small Transmission Owners' exposure to other standards regarding NERC System Operator Certification, and other related standards.

Likes 0	
Dislikes 0	
Response	

Comment submitted by Associated Electric Cooperative, Inc.

"The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."

Comments submitted by SERC

Question 1

SERC appreciates the work of the SDT on this long-running project, and has the following comments on the Control Center definition changes:

- The use of the word 'generally' in a Glossary definition lacks clarity and could lead to inconsistent application among Responsible Entities.
- It is unclear what security principle or finding from the field study/trial excludes 'field assets' such as:
  - data aggregation sites or data acquisition nodes,
  - tie line meters and their data,
  - synchophasors and their data,
  - Cyber Assets used to provide a wide area view, such as frequency monitor.
  - or other technologies such as devices used for monitoring or updating dynamic line ratings under Order 881 and their data
  - from consideration as BES Cyber Assets, since they ultimately exist to provide the information used by the Control Center and its operating personnel to reliably operate the BES. These Cyber Assets are typically not considered by other Attachment 1 criteria since while they are **located at** substations and generation Facilities, the reliability function they serve is to provide data for Control Centers. Suggest that if the SDT wishes to limit the location of BES Cyber Assets associated with Control Centers, the inclusion of 'used by and located at' which is added before Attachment 1 Criterion 2.11, 2.12, and 2.13 in the CIP-002-Y draft accomplishes this.
- The phrasing requiring 'monitor and control' and the description of the exclusion of voice/radio only Control Centers would seem to eliminate most Reliability Coordinator control centers from meeting the glossary term, as RCs do monitor but do not control the BES in real-time, except primarily through the use of voice instructions and electronic communications (such as RCIS) that are excluded from this standard. While Attachment Criterion 1.1 does explicitly call on Control Centers performing the functional obligations of an RC, by the letter of the new definition which includes 'monitor and control' most RCs could exclude themselves. Suggest changing 'monitor and control' phrasing to either 'monitor or control' or 'monitor and/or control'.
- The exclusion of Cyber Assets which only 'monitor' but do not 'monitor and control' does not seem to align with the goal of reliably operating the Interconnection(s), as control of Facilities without accurate monitoring data does not lead to secure and reliable operations. Suggest that instead the 'monitor and control the BES in real-me' phrasing be directed instead at Cyber Assets which either monitor or control and are used to accomplish or achieve compliance with NERC O&P standards with a real-me horizon, as described in the 1-5 numbered items in the definition. This may also eliminate some TO control centers who perform the monitoring functions of the TOP but to operate breakers at up to 500kV use interpersonal communication to member cooperative control rooms which have direct control of the 100-500kV breakers via SCADA to the RTU. There are other instances in the present time where the monitoring and control functional obligations of Transmission Operation are divided between multiple different NERC Responsible Entities and service providers, each of which provide part of the composite actions which satisfy the functional obligations of the RC, BA, TOP, and GOP during normal and emergency operations. Suggest changing 'monitor and control' phrasing to either 'monitor or control' or 'monitor and/or control' to allow for this flexibility without risking a miss in categorizing a BES Cyber Asset/System.
- The change from facilities to 'rooms' may cause confusion or misapplication for other CIP and O&P standards which came after Version 5 such as CIP-012-1 and others in the COM, EOP, IRO, and TOP families since changing the Control Center definition will affect more than just Transmission Owners. Suggest research be done to understand if knock-on effects in complying with these standards will occur.
- The shifting case of the phrase 'Real-time' in Definition items 1, 2, and 3 and 'real-time' in definition items 4 and 5 causes confusion as to the nature of the tasks it includes. Furthermore, the NERC glossary term 'Real-time' is *Present time as opposed to future time*. Is the

intent of the various phrasings of real-time to indicate only actions required at the (instantaneous) present, or does it refer instead to the NERC Time Horizon of Real-Time operations of actions within one hour, especially in the domain of monitoring?

- The Control Center definition removes the "including their associated data centers". This is a major security gap that should be corrected.

Question 2
No additional comments on item #2.

Question 3
SERC appreciates the work of the SDT on this long-running project, and has the following comments on the changes to the Attachment 1 criteria:

- Has the drafting team considered how an entity would demonstrate the net export during non- EEA conditions? Is this creating more burden on the entity to generate a new value? What would happen if one year this is 74 MW for a line and the following year it crosses 75 MW? Such a situation should be addressed in the implementation plan. Would the entity need to recognize this in its annual application of CIP-002 R2 or immediately upon generation upgrades or installations that may impact the rating? (Would this be planned or unplanned?)
- The use of the net export of 75MW utilizes slightly different criteria than the BES definition 75MVA gross nameplate rating (not net export) traditionally used for registration. What is the reasoning for the different value, and was it derived from the field study?

Question 4
SERC appreciates the work of the SDT on this long-running project, and has the following comments on the additional changes in CIP-002-Y:

- In both 4.1.2.2 and 4.2.1.2, it appears in the redline that the word "Each" was dropped from the beginning of the sentence.
- In Attachment 1, Criteria 2.1 and 2.2, the change from 'those' to 'each discrete' phrasing to address the findings of the CIP-002-5.1a appears to create confusion due to the pluralization of 'BES Cyber Systems' appearing just after. Suggest instead to remove the word 'each', so the sentences would read "the only BES Cyber Systems that meet this criterion are discrete shared BES Cyber System that could…"

Consideration of Comments

Project Name:	2021-03 CIP-002 | Draft 1
Comment Period Start Date:	9/26/2023
Comment Period End Date:	11/9/2023
Associated Ballot(s):	2021-03 CIP-002 CIP-002-Y IN 1 ST 2021-03 CIP-002 Implementation Plan IN 1 OT

There were 78 sets of responses, including comments from approximately 172 different people from approximately 111 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 Latrice Harkness (via email) or at (404) 858-8088.

Questions

1. The SDT has modified the Control Center definition based on ambiguity that surfaced during the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

2. The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". This was intentional, to make clear that the BES Cyber Systems to consider differ between Control Centers and other assets such as Transmission stations and Generation resources. In alignment with Part 1 of Attachment 1, BES Cyber Systems 'used by and located at' Control Centers need to be considered. This prevents expanding from Control Centers down into field assets. With respect to other assets, it is BES Cyber Systems 'associated with' the assets that are considered. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

3. The SDT revised CIP-002-Y Attachment 1 Criterion 2.12 based on data obtained from the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

4. Provide any 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
					Jaimin Patal	Saskatchewan Power Corporation (SPC)	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Marc Gomez	Southwestern Power Administration (SWPA)	1	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Bryan Sherrow	Board Of Public Utilities (BPU)	1	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Michael Ayotte	ITC Holdings	1	MRO
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	TVA RBB	Ian Grant	Tennessee Valley Authority	3	SERC
					David Plumb	Tennessee Valley Authority	1	SERC
					Armando Rodriguez	Tennessee Valley Authority	6	SERC
					Nehtisha Rollis	Tennessee Valley Authority	5	SERC
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
Austin Energy		6			Imane Mrini	Austin Energy	6	Texas RE

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
	Imane Mrini			Austin Energy	Michael Dillard	Austin Energy	5	Texas RE
					Lovita Griffin	Austin Energy	3	Texas RE
					Tony Hua	Austin Energy	4	Texas RE
					Thomas Standifur	Austin Energy	1	Texas RE
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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Ryan Strom	Buckeye Power, Inc	4	RF
					Jim Davis	East Kentucky Power Cooperative	1,3	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
California ISO	Monika Montez	2	WECC	ISO/RTO Council Standards Review Committee (SRC)	Monika Montez	CAISO	2	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kathleen Goodman	ISO-NE	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
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	5	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Company Generation		
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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					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	6	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Resources, Inc.		
					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	10	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Reliability Council		
					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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Western Electricity Coordinating Council	Steven Rueckert	10		WECC CIP	Steve Rueckert	WECC	10	WECC
					Morgan King	WECC	10	WECC
					Deb McEndaffer	WECC	10	WECC
					Tom Williams	WECC	10	WECC

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

1. ***The SDT has modified the Control Center definition based on ambiguity that surfaced during the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal*.**

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	No
Document Name	
Comment	
LCRA believes the changing of the definition of Control Center is outside of the scope of the SAR and has unintended consequences to other standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	

LCRA believes the changing of the definition of Control Center is outside of the scope of the SAR and has unintended consequences to other standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF notes that the field test did not include REs from the other functional models impacted by the proposed changes. Therefore, the NAGF recommends preserving the current Control Center definition language and incorporating additional language to directly address the Transmission Owner risk(s). This approach will avoid unintended consequences such as the potential expansion of in scope Cyber Assets applicable under the revised language addressing data centers.	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically	

recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as "perform the reliability tasks" and "associated data centers" are not commonly understood within the industry. The language regarding "reliability tasks" predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a "reliability task". The language regarding "associated data centers" led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico – 3	
Answer	No
Document Name	
Comment	
PNMR (TNMP and PNM) agrees with EEI Comments. Specifically, we support the alternative recommendation to create a new defined term for TOCC. PNMR agrees with leaving the existing definition of Control Center since it is in several other CIP and O&P requirements. We believe changing the definition would require a SAR to change the definition or modify the standards that use the definition. Instead, the SDT should create a new definition Transmission Owner Control Center that is only used in CIP-002 as the NERC Rules of Operating Procedure doesn't recognize Transmission Owners having responsibilities associated with a control center. This avoids adversely affecting a definition a majority do not have a problem with and allow the SDT to scope in Transmission Owner Control Centers in CIP-002 which is the only place it comes up because of a FERC order	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as “perform the reliability tasks” and “associated data centers” are not commonly understood within the industry. The language regarding “reliability tasks” predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a “reliability task”. The language regarding “associated data centers” led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.

Paul Mehlhaff - Sunflower Electric Power Corporation – 1	
Answer	No
Document Name	
Comment	
Sunflower does not believe a modification to the Control Center definition is required.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as	

"perform the reliability tasks" and "associated data centers" are not commonly understood within the industry. The language regarding "reliability tasks" predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a "reliability task". The language regarding "associated data centers" led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.

Claudine Bates - Black Hills Corporation – 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as "perform the reliability tasks" and "associated data centers" are not commonly understood within the industry. The language regarding "reliability tasks" predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a "reliability task". The language regarding "associated data centers" led to questions regarding the extent to which an associated data center extends	

beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as “perform the reliability tasks” and “associated data centers” are not commonly understood within the industry. The language regarding “reliability tasks” predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a “reliability task”. The language regarding “associated data centers” led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.	
Micah Runner - Black Hills Corporation – 1	

Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as "perform the reliability tasks" and "associated data centers" are not commonly understood within the industry. The language regarding "reliability tasks" predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a "reliability task". The language regarding "associated data centers" led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.	
Sheila Suurmeier - Black Hills Corporation – 5	
Answer	No
Document Name	
Comment	

Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as "perform the reliability tasks" and "associated data centers" are not commonly understood within the industry. The language regarding "reliability tasks" predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a "reliability task". The language regarding "associated data centers" led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.	
David Jendras Sr - Ameren - Ameren Services – 3	
Answer	No
Document Name	
Comment	
Ameren supports NAGF's comments on this project	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as “perform the reliability tasks” and “associated data centers” are not commonly understood within the industry. The language regarding “reliability tasks” predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a “reliability task”. The language regarding “associated data centers” led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The standard drafting team has done an excellent job in clarifying a complex definition. The use of one definition for both the control room and associated data center is effective and clear. There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center, however the generators are individual Facilities and are located over a large physical area. The following definition is proposed:	

4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or

5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Thank you for your comment. The phrase “Transmission Facilities at two or more locations” has existed in the Control Center definition since its inception in 2016. This means that an entity must have more than one Transmission Facility and must have Transmission Facilities located at two or more locations. The definition of Facility is “a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”. Therefore, a line, which is generally considered to be bounded by breakers that operate to protect the BES Element, is a single Facility with multiple locations based on breakers that can be used to impact line flow. An entity who solely controls a single line does not meet the Control Center definition because it only has a single Transmission Facility. An entity who solely controls breakers at a single location (e.g., switching station) for multiple lines does not meet the Control Center definition because it only has a single location. To be considered a Control Center the entity has to control two or more Transmission Facilities at two or more locations. Insertion of “separate physical” does not sufficiently clarify locations. Examples will be provided in the Technical Rationale.

Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.”

Jay Sethi - Manitoba Hydro - 1,3,5,6 – MRO

Answer	No
Document Name	

Comment	
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Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The phrase “Transmission Facilities at two or more locations” has existed in the Control Center definition since its inception in 2016. This means that an entity must have more than one Transmission Facility and must have Transmission Facilities located at two or more locations. The definition of Facility is “a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”. Therefore, a line, which is generally considered to be bounded by breakers that operate to protect the BES Element, is a single Facility with multiple locations based on breakers that can be used to impact line flow. An entity who solely controls a single line does not meet the Control Center definition because it only has a single Transmission Facility. An entity who solely controls breakers at a single location (e.g., switching station) for multiple lines does not meet the Control Center definition because it only has a single location. To be considered a Control Center the entity has to control two	

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Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
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Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The phrase "Transmission Facilities at two or more locations" has existed in the Control Center definition since its inception in 2016. This means that an entity must have more than one Transmission Facility and must have Transmission Facilities located at two or more locations. The definition of Facility is "a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)". Therefore, a line, which is generally considered to be bounded by breakers that operate to protect the BES Element, is a single Facility with multiple locations based on breakers that can be used to impact line flow. An entity who solely controls a single line does not meet the Control Center definition because it only has a single Transmission Facility. An entity who solely controls breakers at a single location (e.g., switching station) for multiple lines does not meet the Control Center definition because it only has a single location. To be considered a Control Center the entity has to control two or more Transmission Facilities at two or more locations. Insertion of "separate physical" does not sufficiently clarify locations. Examples will be provided in the Technical Rationale. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT is in agreement with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
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Likes 0	
Dislikes 0	
Response	
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Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The standard drafting team has done an excellent job in clarifying a complex definition. The use of one definition for both the control room and associated data center is effective and clear. There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center, however the generators are individual Facilities and are located over a large physical area. The following definition is proposed: 4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or 5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The phrase "Transmission Facilities at two or more locations" has existed in the Control Center definition since its inception in 2016. This means that an entity must have more than one Transmission Facility and must have Transmission Facilities located at two or more locations. The definition of Facility is "a set of electrical equipment that operates as a single Bulk Electric	

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Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
Initially, we felt the SAR only allowed for modification to the definition of Control Center as it relates to TO's only. After meeting and talking with the SDT, during their recent webinar, we feel that changing the definition of Control Center for TOs, RCs, BAs, and GOPs, collectively, is allowed, and is appropriate. However, it would not be acceptable to us if the SDT proposed changing the definition for TOs, RCs, and/or BAs, collectively, but excluded GOPs.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT is in agreement with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.”

Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT is in agreement with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.”	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	

Comment	
Please see comments by Marty Hostler, NCPA. Thanks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT is in agreement with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.”	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	No
Document Name	
Comment	
WEC Energy Group supports the comments of the MRO NSRF. Additionally, we support the following comment proffered by EEI: *"Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition."*	
Likes 0	

Dislikes 0	

Response

Thank you for your comment. The phrase “Transmission Facilities at two or more locations” has existed in the Control Center definition since its inception in 2016. This means that an entity must have more than one Transmission Facility and must have Transmission Facilities located at two or more locations. The definition of Facility is “a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”. Therefore, a line, which is generally considered to be bounded by breakers that operate to protect the BES Element, is a single Facility with multiple locations based on breakers that can be used to impact line flow. An entity who solely controls a single line does not meet the Control Center definition because it only has a single Transmission Facility. An entity who solely controls breakers at a single location (e.g., switching station) for multiple lines does not meet the Control Center definition because it only has a single location. To be considered a Control Center the entity has to control two or more Transmission Facilities at two or more locations. Insertion of “separate physical” does not sufficiently clarify locations. Examples will be provided in the Technical Rationale.

Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT is in agreement with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.”

Regarding the proposal to consider not modifying the Control Center definition, the portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as “perform the reliability tasks” and “associated data centers” are not commonly understood within the industry. The language regarding “reliability tasks” predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a “reliability task”. The language regarding “associated data centers” led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES

in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	No
Document Name	
Comment	
Buckeye supports the comments made by ACES: ACES suggests changing “Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units” to “Field assets, such as remote terminal units, are excluded from the scope of the Control Center’s definition” to avoid ambiguity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees to modify the sentence containing the phrase “generally housed in a centralized location" to avoid ambiguity and to start the sentence with “Field assets”. In addition, the term “data aggregators” will be added as an example of a field asset for additional clarity. Front-end processors used to aggregate all data coming into an EMS are not considered to be field assets because these centrally-located Cyber Assets are required to monitor and control the BES in Real-time, whereas data aggregators in the field process only a subset of data such as multi-RTU circuits.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. – 1	
Answer	No
Document Name	
Comment	

AEPC signed on to ACES comments below: ACES suggests changing "Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units" to "Field assets, such as remote terminal units, are excluded from the scope of the Control Center's definition" to avoid ambiguity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees to modify the sentence containing the phrase "generally housed in a centralized location" to avoid ambiguity and to start the sentence with "Field assets". In addition, the term "data aggregators" will be added as an example of a field asset for additional clarity. Front-end processors used to aggregate all data coming into an EMS are not considered to be field assets because these centrally-located Cyber Assets are required to monitor and control the BES in Real-time, whereas data aggregators in the field process only a subset of data such as multi-RTU circuits.	
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	
ACES suggests changing "Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units" to "Field assets, such as remote terminal units, are excluded from the scope of the Control Center's definition" to avoid ambiguity.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT agrees to modify the sentence containing the phrase “generally housed in a centralized location" to avoid ambiguity and to start the sentence with “Field assets”. In addition, the term “data aggregators” will be added as an example of a field asset for additional clarity. Front-end processors used to aggregate all data coming into an EMS are not considered to be field assets because these centrally-located Cyber Assets are required to monitor and control the BES in Real-time, whereas data aggregators in the field process only a subset of data such as multi-RTU circuits.

Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
While we can agree with the proposed changes we do have a couple suggestions. The last sentence of the proposed first paragraph is "Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units." 1. It's not obvious to us the purpose of the words "are generally housed in a centralized location and". Could they be deleted? Also, the term "field assets" is used in that sentence. 2. The October 30th webinar conducted by the SDT included "data aggregators" as a type of field asset. Because of their common use, we recommend adding data aggregators alongside remote terminal units in that text.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees to modify the sentence containing the phrase “generally housed in a centralized location" to avoid ambiguity and to start the sentence with “Field assets”. In addition, the term “data aggregators” will be added as an example of a field asset for additional clarity. Front-end processors used to aggregate all data coming into an EMS are not considered to be field assets because these centrally-located Cyber Assets are required to monitor and control the BES in Real-time, whereas data aggregators in the field process only a subset of data such as multi-RTU circuits.	

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	No
Document Name	
Comment	

NST disagrees with the proposed changes to the definition of "Control Center" for the following reasons:

> NST has helped a multitude of Registered Entities achieve and maintain compliance with the CIP Standards, beginning with Version 1, and we have yet to interact with one whose Subject Matter Experts were unclear about the meaning of "facility" in the Control Center definition that became effective July 1, 2016. We have likewise encountered no confusion about what a "data center" is. NST acknowledges the field test report's statement that a number of TOs "have struggled to interpret the Control Center definition," but we also note the approximately 20 TOs that provided information during the study represents a very small percentage of Registered Entities subject to the CIP Standards.

> NST believes the proposed change from "data centers" to "spaces" to connote where a Control Center's Cyber Assets might reside reduces rather than increases clarity. What, exactly, is a "space"?

> The proposed changes fail to address an important question that the advent of requirements applicable to communication links between Control Centers (CIP-012) brought to the fore: Is a data center that houses some of a Control Center's Cyber Assets (e.g., SCADA/EMS servers) itself a Control Center? A CIP-012-1 webinar presented by NERC and the six Regional Entities on June 2, 2022 stated, "A data center is a Control Center." NST considers this assertion to be both incorrect and problematic for several reasons, including the fact that while it's possible for a Control Center's operators and the servers they use to be in different Zip Codes, it's also entirely possible for the operators and all the Cyber Assets they need to be in the same room of the same building. Are there TWO Control Centers in the latter instance? Of course not.

NST believes it is essential that this issue be addressed by any attempt to update the current definition of Control Center, and we respectfully submit the following alternate language for the SDT's consideration:

A Bulk Electric System asset used by the operating personnel listed below to monitor and control the Bulk Electric System in real-time. A Control Center includes:
- Workspaces for operating personnel

- Cyber Assets used by operating personnel to monitor and control the BES in real-time. Some of those Cyber Assets may be, in some instances, in a different physical location (e.g., a remote data center) than the operator workspaces 1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator; 2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority; 3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations; 4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or 5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more locations in real-time.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as “perform the reliability tasks” and “associated data centers” are not commonly understood within the industry. The language regarding “reliability tasks” predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a “reliability task”. The language regarding “associated data centers” led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the

commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.

The SDT agrees with comments received regarding the challenges introduced by the use of terms ‘rooms’ and ‘spaces’ within the Control Center definition. Pursuant to these comments, the SDT is returning to the term ‘facilities’ to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.

The SDT agrees that clarity is needed regarding the application of the Control Center definition with respect to requirements applicable to communication links between Control Centers. The SDT considered the recommended approach to rewrite the definition as “A BES asset…”. Ultimately, the SDT was unable to support the recommended changes because there is no inclusion of a Control Center as a Bulk Electric System asset in the current BES definition, and the 2021-03 SAR does not include modifications to the BES definition. The alternative approach proposed by the SDT eliminates the term ‘spaces’ and instead incorporates “any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time” into the definition. This, in effect, defines a single Control Center to contain the facilities used by operating personnel (e.g., workspaces for operating personnel) to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.

Kimberly Turco - Constellation – 6	
Answer	No
Document Name	
Comment	

From the Technical Rationale "The phrase “any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time” was developed to replace “associated data center”. Do the spaces located in a room that does not house operating personnel, but is in the same building as a room that houses operating personnel (shared street address) and the spaces located in a separate building from any rooms that house operating personnel get classified as Control Centers? These spaces were known as “associated data centers” and were not included in the count of Control Centers. Clarifying language is needed in the definition that states if the rooms, that do not physically host operating personnel, are not classified as Control Centers.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.

The SDT agrees that clarity is needed regarding the application of the Control Center definition with respect to requirements applicable to communication links between Control Centers. The SDT considered the recommended approach to rewrite the definition as "A BES asset…". Ultimately, the SDT was unable to support the recommended changes because there is no inclusion of a Control Center as a Bulk Electric System asset in the current BES definition, and the 2021-03 SAR does not include modifications to the BES definition. The alternative approach proposed by the SDT eliminates the term 'spaces' and instead incorporates "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time" into the definition. This, in effect, defines a single Control Center to contain the facilities used by operating personnel (e.g., workspaces for operating personnel) to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.

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

Answer	No
Document Name	

Comment

The proposed changes are too specific to the architecture of the building and does not provide clarity on what is meant by "hosting".

For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

{C}1) If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers but no one is assigned to that desk, is the engineering office a Control Center? or

{C}2) If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or

{C}3) If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or

{C}4) If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center?

{C}5) If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a

Control Center?

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. Further, the concept of 'hosting' has been replaced with 'used by' to provide some added clarity. With respect to the included Cyber Assets, revisions to the definition have been proposed based on comments received to clarify that the Control Center includes "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time." The location of other Cyber Assets that are not used by operating personnel to monitor and control the BES in Real-time would not be considered part of the Control Center.

An entity may have facilities that do not meet the Control Center definition solely because they are not used by operating personnel to monitor and control the BES in Real-time (either as primary or backup location). The entity would need to identify the facilities as a Control Center in the event that conditions necessitated use of the facilities by operating personnel to monitor and control the BES in Real-time during emergency conditions.

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	
Comment	
OPG supports NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with comments received regarding the challenges introduced by the use of terms ‘rooms’ and ‘spaces’ within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term ‘facilities’ to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. Further, the concept of ‘hosting’ has been replaced with ‘used by’ to provide some added clarity. With respect to the included Cyber Assets, revisions to the definition have been proposed based on comments received to clarify that the Control Center includes “any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time.” The location of other Cyber Assets that are not used by operating personnel to monitor and control the BES in Real-time would not be considered part of the Control Center. An entity may have facilities that do not meet the Control Center definition solely because they are not used by operating personnel to monitor and control the BES in Real-time (either as primary or backup location). The entity would need to identify the facilities as a Control Center in the event that conditions necessitated use of the facilities by operating personnel to monitor and control the BES in Real-time during emergency conditions.	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	No
Document Name	
Comment	

While WECC recognizes the need for the SDT to provide clarity to this complex definition, some of the modifications to the Control Center definition appear to have also created unintended consequences as well. In the context of Associated Data Center -

"A space that houses Cyber Assets used by operating personnel to monitor and control the BES in real-time may be:

• located in the same room that houses operating personnel."

This proposed revision appears to bring a home office where personnel using a Cyber Asset with Interact Remote Access (IRA) to monitor and control the BES in real-time into scope as a Control Center.

In the context of IRA, the standards have not brought in the remote Cyber Asset into scope as any applicable system of the standards, but the first bullet appears to bring a home office into scope as a Control Center and Cyber Asset with this capability into scope as a BCA.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. Further, the concept of 'hosting' has been replaced with 'used by' to provide some added clarity. With respect to the included Cyber Assets, revisions to the definition have been proposed based on comments received to clarify that the Control Center includes "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time." The location of other Cyber Assets that are not used by operating personnel to monitor and control the BES in Real-time would not be considered part of the Control Center.

Alison MacKellar - Constellation - 5

Answer	No
Document Name	

Comment

From the Technical Rationale "The phrase "any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time" was developed to replace "associated data center". Do the spaces located in a room that does not house operating personnel, but is in the same building as a room that houses operating personnel (shared street address) and the spaces located in a separate building from any rooms that house operating personnel get classified as Control Centers? These spaces were known as "associated data centers" and were not included in the count of Control Centers. Clarifying language is needed in the definition that states if the rooms, that do not physically host operating personnel, are not classified as Control Centers. Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. Further, the concept of 'hosting' has been replaced with 'used by' to provide some added clarity. With respect to the included Cyber Assets, revisions to the definition have been proposed based on comments received to clarify that the Control Center includes "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time." The location of other Cyber Assets that are not used by operating personnel to monitor and control the BES in Real-time would not be considered part of the Control Center.

Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	

Suggest to change to "One or more designated rooms or buildings…" in order to avoid calling any area including remote locations where operating personnel may monitor and/or control remotely with their approved cyber assets, such as engineering workstation. Suggest to define operating personnel so that the role is only active inside Control Center (i.e. remote monitoring and controlling outside of Control Center not allowed)	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. Further, the concept of 'hosting' has been replaced with 'used by' to provide some added clarity. With respect to the included Cyber Assets, revisions to the definition have been proposed based on comments received to clarify that the Control Center includes "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time." The location of other Cyber Assets that are not used by operating personnel to monitor and control the BES in Real-time would not be considered part of the Control Center. The SDT has considered use of the term 'designated' during the drafting process, but determined that it introduces complexities as there is no requirement for an entity to create such a designation. Further, use of the language "to monitor and control the BES in Real-time" is intended to ensure that the mere presence of operating personnel outside of the Control Center does not bring a facility into the Control Center definition provided that the operating personnel are not monitoring and controlling the BES in Real-time from that facility.	
Thomas Standifur - Austin Energy - 1	
Answer	No
Document Name	
Comment	

Austin Energy believes the proposed change to the definition of Control Center is too broad and vague with the inclusion of "any spaces that house". In addition, a change to this core definition could have cascading impacts to other NERC standards and introduce potential conflict and confusion. In addition, the SAR does not include/request a definition change.	
Likes 1	Austin Energy, 6, Mrini Imane
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards. The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. Further, the concept of 'hosting' has been replaced with 'used by' to provide some added clarity. With respect to the included Cyber Assets, revisions to the definition have been proposed based on comments received to clarify that the Control Center includes "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time." The location of other Cyber Assets that are not used by operating personnel to monitor and control the BES in Real-time would not be considered part of the Control Center.	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	No
Document Name	
Comment	

The proposed change to the definition of Control Center is too broad and vague with the inclusion of "any spaces that house". In addition, a change to this core definition could have cascading impacts to other NERC standards and introduce potential conflict and confusion. In addition, the SAR does not include/request a definition change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards. The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. Further, the concept of 'hosting' has been replaced with 'used by' to provide some added clarity. With respect to the included Cyber Assets, revisions to the definition have been proposed based on comments received to clarify that the Control Center includes "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time." The location of other Cyber Assets that are not used by operating personnel to monitor and control the BES in Real-time would not be considered part of the Control Center.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface): **Control Center** - One or more **facilities** where a responsible entity **houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **located** in a centralized location and exclude field assets such as remote terminal units. 1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator; 2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority; 3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations; 4. Transmission Owner **facilities that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or 5. Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for** generation Facilities at two or more **separate physical** locations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the	

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Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

Dominion Energy supports EEI comments and recommends the changes proposed for the definition by EEI.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."

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Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.” The SDT agrees with comments received regarding the challenges introduced by the use of terms ‘rooms’ and ‘spaces’ within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term ‘facilities’ to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.	

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Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes	

that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."

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Kinte Whitehead - Exelon – 3	
Answer	No
Document Name	
Comment	

Exelon is responding in support of EEI's response to this question.	
Likes 0	
Dislikes 0	

Response

Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."

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Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees with the comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.” The SDT agrees with comments received regarding the challenges introduced by the use of terms ‘rooms’ and ‘spaces’ within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term ‘facilities’ to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.	

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TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 – RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes	

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Daniel Gacek - Exelon – 1

Answer	No
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."

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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 Insititute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.” The SDT agrees with comments received regarding the challenges introduced by the use of terms ‘rooms’ and ‘spaces’ within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term ‘facilities’ to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.	

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Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes	

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Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No
Document Name	
Comment	

Duke Energy supports NAGF comments on the Control Center definition and appreciates the work of the Drafting Team, including all the industry engagment through the previous informal comment period. Duke Energy also support's EEI's comments on the concerns regarding scope expansion in the draft language for GOPs. If the Drafting Teams feels that the "associated data center piece" must be expanded on , and that they cannot keep the body of the current definition as NAGF suggests, Duke Energy suggests the following alternative language:

One or more facilities where a responsible entity houses operating personnel who perform the functional entity obligations described below, including locations that contain BES Cyber Systems used by those operating personnel to support the functional entity's capability to monitor and have control authority of the Bulk Electric System (BES) in Real-time.

1. Reliability-related tasks of a Reliability Coordinator,

2. Reliability related tasks of a Balancing Authority,

3. Reliability-related tasks of a Transmission Operator at two or more locations,

4. Reliability-related tasks of a Transmission Owner at two or more locations,

5. Generator Operator having the capability to electronically control generation Facilities at two or more locations.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."

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Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Tacoma Power appreciates the revisions made by the SDT based on the previous informal comment period. Tacoma Power agrees with many of the changes made to the Control Center definition. However, the Control Center definition is still ambiguous on exactly what	

Cyber Assets are intended to be included. For example, is the intent to include control panels used by operating personnel, the energy management system or the entire system including servers and communication gear? Tacoma Power recommends additional changes to provide clarity, as follows. Instead of referring to Cyber Assets, the definition should refer to BES Cyber Systems, as this would capture the associated data centers. This change would leverage existing NERC Glossary of Terms to reduce the ambiguity. Proposed change: “including any spaces that house the **BES** Cyber **System** used by operating personnel to monitor and control the BES in real-time."	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Thank you for your comment. With respect to the proposal to replace “Cyber Asset” in the revised definition with “BES Cyber System”, the SDT is unable to support the use of “BES Cyber Systems” in the Control Center definition, as this will introduce a circular reference between the definition and the requirements of CIP-002. An entity must identify its Control Center(s) prior to application of CIP-002, which is where the entity will identify and categorize its BES Cyber Systems and their associated BES Cyber Assets. At this time, the SDT recommends retaining the term “Cyber Asset”.	
Megan Melham - Decatur Energy Center LLC – 5	
Answer	No
Document Name	
Comment	
The field test was only conducted and directed at Transmission Operators and Transmission Owners and doesn’t consider the impact to registered entities outside of this range. Recommend preserving the previous language and adding additional language to address the Transmission Owner risk(s). Additionally, the expanded wording used to address “data centers” could have unintended consequences such as the potential expansion in scope of applicable Cyber Assets and rooms. An example of excluded field assets is given as the remote	

terminal units; it's unclear if protection relays and the communication equipment used to provide real-time information to the operating personnel would also fit under this exclusion.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator." The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. Per comments received, the SDT agrees to modify the sentence containing the phrase "generally housed in a centralized location" to avoid ambiguity and to start the sentence with "Field assets". In addition, the term "data aggregators" will be added as an example of a field asset for additional clarification. Front-end processors used to aggregate all data coming into an EMS are not considered to be field assets because these centrally-located Cyber Assets are required to monitor and control the BES in Real-time, whereas data aggregators in the field process only a subset of data such as multi-RTU circuits.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy supports EEI's comments which state:

EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface):

Control Center - One or more **facilities** where a responsible entity **houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **Cyber Assets BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **located** in a centralized location and exclude field assets such as remote terminal units.

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations;

4. Transmission Owner **facilities who that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or

5. Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for** generation Facilities at two or more **separate physical** locations.

Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a

separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition.	
Likes 0	
Dislikes 0	

Response

Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as "perform the reliability tasks" and "associated data centers" are not commonly understood within the industry. The language regarding "reliability tasks" predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a "reliability task". The language regarding "associated data centers" led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.

Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."

The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.

With respect to the proposal to replace "Cyber Asset" in the revised definition with "BES Cyber System", the SDT is unable to support the use of "BES Cyber Systems" in the Control Center definition, as this will introduce a circular reference between the definition and the requirements of CIP-002. An entity must identify its Control Center(s) prior to application of CIP-002, which is where the entity will identify and categorize its BES Cyber Systems and their associated BES Cyber Assets. At this time, the SDT recommends retaining the term "Cyber Asset".

The phrase "Transmission Facilities at two or more locations" has existed in the Control Center definition since its inception in 2016. This means that an entity must have more than one Transmission Facility and must have Transmission Facilities located at two or more locations. The definition of Facility is "a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)". Therefore, a line, which is considered to be bounded by breakers that operate to protect the BES Element, is a single Facility with multiple locations based on breakers that can be used to impact line flow. An entity who solely controls a single line does not meet the Control Center definition because it only has a single Transmission Facility. An entity who solely controls breakers at a single location (e.g., switching station) for multiple lines does not meet the Control Center definition because it only has a single location. To be considered a Control Center the entity has to control two or more Transmission Facilities at two or more locations. Insertion of "separate physical" does not sufficiently clarify locations.

Kent Feliks - AEP – 3

Answer	No
Document Name	

Comment

AEP supports the comments made by EEI. Specifically:

EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that

can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface): **Control Center** - One or more **facilities** where a responsible entity **houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **located** in a centralized location and exclude field assets such as remote terminal units. 1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator; 2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority; 3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations; 4. Transmission Owner **facilities who that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or 5. Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for** generation Facilities at two or more **separate physical** locations Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition. Kent Feliks on behalf of AEP in Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as “perform the reliability tasks” and “associated data centers” are not commonly understood within the industry. The language regarding “reliability tasks” predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a “reliability task”. The language regarding “associated data centers” led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.” The SDT agrees with comments received regarding the challenges introduced by the use of terms ‘rooms’ and ‘spaces’ within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term ‘facilities’ to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. With respect to the proposal to replace “Cyber Asset” in the revised definition with “BES Cyber System”, the SDT is unable to support the use of “BES Cyber Systems” in the Control Center definition, as this will introduce a circular reference between the definition and the requirements of CIP-002. An entity must identify its Control Center(s) prior to application of CIP-002, which is where the entity will identify and categorize its BES Cyber Systems and their associated BES Cyber Assets. At this time, the SDT recommends retaining the term “Cyber Asset”.

The phrase "Transmission Facilities at two or more locations" has existed in the Control Center definition since its inception in 2016. This means that an entity must have more than one Transmission Facility and must have Transmission Facilities located at two or more locations. The definition of Facility is "a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)". Therefore, a line, which is considered to be bounded by breakers that operate to protect the BES Element, is a single Facility with multiple locations based on breakers that can be used to impact line flow. An entity who solely controls a single line does not meet the Control Center definition because it only has a single Transmission Facility. An entity who solely controls breakers at a single location (e.g., switching station) for multiple lines does not meet the Control Center definition because it only has a single location. To be considered a Control Center the entity has to control two or more Transmission Facilities at two or more locations. Insertion of "separate physical" does not sufficiently clarify locations.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE supports EEI's comments: "EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface): **Control Center** - One or more **facilities rooms** where a responsible entity **hosts houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **any spaces that house the Cyber Assets BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **Cyber Assets BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **housed located** in a centralized location and exclude field assets such as remote terminal units.	

Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator; Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority; Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations; . **Operating personnel of a** Transmission Owner **facilities who that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for who have the capability to electronically control** generation Facilities at two or more **separate physical** locations**; in real-time**. Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as “perform the reliability tasks” and “associated data centers” are not commonly understood within the industry. The language regarding “reliability tasks” predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a “reliability task”. The language regarding “associated data centers” led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term	

Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.

Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.”

The SDT agrees with comments received regarding the challenges introduced by the use of terms ‘rooms’ and ‘spaces’ within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term ‘facilities’ to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.

With respect to the proposal to replace “Cyber Asset” in the revised definition with “BES Cyber System”, the SDT is unable to support the use of “BES Cyber Systems” in the Control Center definition, as this will introduce a circular reference between the definition and the requirements of CIP-002. An entity must identify its Control Center(s) prior to application of CIP-002, which is where the entity will identify and categorize its BES Cyber Systems and their associated BES Cyber Assets. At this time, the SDT recommends retaining the term “Cyber Asset”.

The phrase “Transmission Facilities at two or more locations” has existed in the Control Center definition since its inception in 2016. This means that an entity must have more than one Transmission Facility and must have Transmission Facilities located at two or more locations. The definition of Facility is “a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)”. Therefore, a line, which is considered to be bounded by breakers that operate to protect the BES Element, is a single Facility with multiple locations based on breakers that can be used to impact line flow. An entity who solely controls a single line does not meet the Control Center definition because it only has a single Transmission Facility. An entity who solely controls breakers at a single location (e.g., switching station) for multiple lines does not meet the Control Center definition because it only has a single location. To be considered a Control Center the entity has to control two or more Transmission Facilities at two or more locations. Insertion of “separate physical” does not sufficiently clarify locations.

Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS does not agree with the proposed changes but does supports the comments that were submitted by EEI on behalf of their members to improve the definition for Control Centers. Either by incorporating their proposed submitted changes or by their submitted suggestion of creating a CIP-002 specific definition for Control Centers targeting TO Control Centers.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as "perform the reliability tasks" and "associated data centers" are not commonly understood within the industry. The language regarding "reliability tasks" predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a "reliability task". The language regarding "associated data centers" led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language	

"perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator." The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time. With respect to the proposal to replace "Cyber Asset" in the revised definition with "BES Cyber System", the SDT is unable to support the use of "BES Cyber Systems" in the Control Center definition, as this will introduce a circular reference between the definition and the requirements of CIP-002. An entity must identify its Control Center(s) prior to application of CIP-002, which is where the entity will identify and categorize its BES Cyber Systems and their associated BES Cyber Assets. At this time, the SDT recommends retaining the term "Cyber Asset". The phrase "Transmission Facilities at two or more locations" has existed in the Control Center definition since its inception in 2016. This means that an entity must have more than one Transmission Facility and must have Transmission Facilities located at two or more locations. The definition of Facility is "a set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)". Therefore, a line, which is considered to be bounded by breakers that operate to protect the BES Element, is a single Facility with multiple locations based on breakers that can be used to impact line flow. An entity who solely controls a single line does not meet the Control Center definition because it only has a single Transmission Facility. An entity who solely controls breakers at a single location (e.g., switching station) for multiple lines does not meet the Control Center definition because it only has a single location. To be considered a Control Center the entity has to control two or more Transmission Facilities at two or more locations. Insertion of "separate physical" does not sufficiently clarify locations.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County – 1	
Answer	No
Document Name	
Comment	

The description is wordy, is a run-on sentence, and preserves the existing ambiguity regarding what "monitor and control" is in the context of real-time. Our TO organization has an agreement with a third party to "monitor" our limited assets. Many small TO utilities do not "monitor and control in real-time". Monitoring is passive and after-the-fact, not real-time. TO's do not "operate", according to NERC functional definitions, and thus cannot have "operating personnel". We recognize there are larger TO's who have massive Control Centers, and by definition they do "monitor and operate" and should be registered as TOPs. Furthermore, smaller entities like us may have the ability to select a device and open it or close it, but it is only if we are directed to act by our TOP or RC through our agreements. This is not real-time because we do not monitor the overall BES and are not aware of the overall impacts of the operation. Any operation we do is clearly limited, and it is approved ahead-of-time for maintenance and testing purposes, unless otherwise directed. This, in our interpretation, is not real-time operation. Our staff's focus is monitoring and operating a distribution system, the inclusion of our facilities in the definition of a "Control Center" over states what our staff does, and it leads us to believe that NERC System Operator Certification may be required for anyone who may electronically switch their 100kV assets for working on their own distribution system.

A second concern is that smaller generators may use two separate and distinct systems to manage two separate generation facilities from a common room. Furthermore, generation Facilities may be geographically separated, or in the same local area. Bullet #5 doesn't distinguish between NERC registered generation and other small generation. We feel the inclusion of a 980Kw generator in a larger 88Mw facility could be interpreted to be two generation Facilities operated from the same location, thereby making this a Control Center under the new definition.

Overall, it is our feeling that bullets 4 and 5 should not be included, and that this definition should focus on BAs, RCs, and TOPs. The lead in language should be amended to state:

"Control Center - One or more facilities where an RC, BA or TOP hosts NERC Certified operating personnel to monitor and control the Bulk Electric System (BES) in real-time, as described below, including location of the associated Cyber Assets used by to monitor and control the BES in real-time. "

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Thank you for your comment. The SDT has made revisions in an effort to improve sentence structure and clarity. While covering reliability gaps, it is important not to disincentivize effective operations with compliance obligations with limited reliability gain. Therefore, it is necessary to clearly define the line where medium impact BES Cyber Systems should be categorized regarding both the TO and TOP. We recognize the existence of TO entities who have a contractual arrangement for a third party to provide TOP coverage of their BES transmission, which can improve reliability and provide cost savings. However, the TO may incorporate Real-time monitoring and control of their Facilities to improve maintenance operations, especially in regard to public safety and efficient switching operations outside of the functional obligation of the TOP. This may be encompassed within a facility meeting the definition of the Control Center. The TO's ability to monitor and control in Real-time includes use of a SCADA system to detect Protection System operations and the ability to operate sectionalizing switches and breakers remotely allowing maintenance work to begin and to restore power without the need to dispatch personnel long distances simply to operate switches and breakers. Further, TO Real-time control can include SCADA remote operation of breakers to clear a dangling transmission line as reported by the public or emergency services after a car-pole accident. Whether the action above can only be implemented after TOP approval is not material in establishing whether a TO operates a Control Center.

Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

BC Hydro appreciates drafting team's efforts and the opportunity to comment, and provides the following.

Proposed modifications to the definition of Control Centre don't align with CIP-002.5.1a Attachment 1 high and medium impact Control Center criteria 1.1 to 1.4 and 2.11 to 2.13 as these Control Centre criteria still use "perform functional obligations" language which is equivalent to "to perform the reliability tasks" SDT tried to replace. For instance, in a GOP control room, the operating personnel are capable of controlling generating units at two generation plants, but they don't perform GOP obligations that are only taken by the GOP

System Operators. Even though this GOP control room would become a Control Centre based on the modified Control Centre definition, it wouldn’t meet any high or medium Control Center impact rating criteria thus only becoming a low impact Control Center. The language around "the capability to electronically control Transmission Facilities at two or more locations has a Control Center" is vague and could encompass facilities and locations that definitely should not be considered control centers. The SDT is requested to consider not removing ‘reliability-related tasks' from the currently defined terms as this will further clarify who is 'operating personnel'. BCH also seeks clarity on the use of the word 'capability'. SDT should allow for provisions where protections have been implemented that reduce/impair 'capability', but there still exists the possibility without those protections. The inclusion of points 4 and 5 (in Control Center Definition) for consideration of operating personnel (i.e. technicians and electricians may qualify) would effectively turn any generation control room that has the capability to electronically control a local and remote BES asset into a Control Center. BC Hydro suggest that SDT provide some use cases and examples to clarify this, and makes the following recommendations: 1) Modify CIP-002 Attachment 1 criteria 1.1 to 1.4 and 2.11 to 2.13 to change “perform functional obligations” to “control Facilities”. 2) Provide clarity of the use term ‘operating personnel’ in item 4 and 5 of Control Center definition and use of the term ‘capability’ with use cases and examples. 3) In the Control Center definition suggest changing the points 1 or 2 or 3 or 4 or 5 to: 1 or 2 or 3 or (1 or 2 or 3 and 4) or (1 or 2 or 3 and 5). This will ensure that Real-time monitoring and control of the BES is occurring, instead of including in the Control Center definition control rooms only performing local load control.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT reviewed the SAR and agrees that addressing the language "perform the functional obligations of" throughout CIP-002 is within scope. The SDT proposed additional changes to replace each instance of the phrase "perform the functional obligations of" with specific references to the relevant Registered Entities.

The SDT agrees with concerns regarding use of the language "capability to electronically control" and has eliminated the term "electronically" in its updated proposal. With respect to the Transmission Owner, the SDT has replaced the language with "capability to control BES Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA)". This clearly eliminates TOs who are only able to control the BES by issuing verbal instructions to field personnel.

Further, the language in (5) related to Generator Operators has been modified pursuant to comments to avoid inadvertently expanding the scope for Generator Operators. The SDT is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."

Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The ISO/RTO Council (IRC) Standards Review Committee (SRC) is concerned that the phrase "electronically control . . ." in paragraphs 4 and 5 of the proposed Control Center definition does not achieve the purpose described in the Technical Rationale of differentiating between remote control in Real-time and control via instructions issued to field personnel. Specifically, the SRC is concerned that the term "electronically" could cause confusion, as the radios or telephones used to issue instructions to field personnel could be viewed as an electronic form of control, while Real-time control that relies on mechanical or fiber optic means of control might be considered to fall outside the bounds of electronic control.

The SRC proposes that the drafting team consider removing the word "electronically" from paragraphs 4 and 5. The SRC believes that the qualifier "in real-time" at the end of each paragraph should suffice to achieve the goal described in the Technical Rationale. Dispatching field personnel to a location to perform an action would arguably not count as Real-time control, since time would elapse between the

issuance and the execution of an instruction while the field personnel travel to the location and execute the actions needed to control the impacted Facility. On the other hand, a scenario in which instructions are being conveyed via radio or telephone to field personnel who are already on-site at a Facility and will execute the instructions within seconds of receiving them might be considered Real-time control, but this may be consistent with the overall purpose of the Control Center definition. Additionally, the SRC notes that the proposed definition alternates between using the capitalized term "Real-time," which is defined in the NERC Glossary of Terms, and the uncapitalized term "real-time." The SRC requests that the drafting team adopt a consistent capitalization approach to clarify whether the definition from the NERC Glossary of Terms is intended to apply. If the NERC Glossary definition is not intended to apply, or if it is only intended to apply in some locations, the SRC requests that the drafting team use a different term in place of the uncapitalized term "real-time" to avoid confusion with the capitalized term defined in the NERC Glossary. Finally, in order to provide further clarity, the SRC suggests that the first two sentences of the definition of a Control Center be revised and combined into a single sentence that reads as follows: Control Center: One or more rooms where a responsible entity hosts any of the operating personnel described in paragraphs 1-5 below who monitor and control or monitor and direct action for the Bulk Electric System (BES) in Real-time, and any spaces that house the Cyber Assets used by operating personnel to monitor and control or monitor and direct action for the BES in Real-time, excluding field assets such as remote terminal units.

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT agrees with concerns regarding use of the language "capability to electronically control" and has eliminated the term "electronically" in its updated proposal. With respect to the Transmission Owner, the SDT has replaced the language with "capability to control BES Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA)". This clearly eliminates TOs who are only able to control the BES by issuing verbal instructions to field personnel. Further, the language in (5) related to Generator Operators has been modified pursuant to comments to avoid inadvertently expanding the scope for Generator Operators. The SDT is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" will be adequate to avoid expanding the Control Center scope for Generator Operators. Further,

the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator." Regarding the recommendation to replace "monitor and control" with "monitor and control or monitor and direct action for", the SDT is concerned that the additional language may add to the confusion. The language "monitor and control" has been a part of the Control Center definition since its inception and the SDT is not aware of confusion on the part of RCs, BAs or TOPs regarding application to their facilities, whether they have the capability to operate devices via Cyber Assets (e.g., a SCADA system) or whether they instruct other entities to operate devices.

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	
Thank you for your comment. The SDT agrees with concerns regarding use of the language "capability to electronically control" and has eliminated the term "electronically" in its updated proposal. With respect to the Transmission Owner, the SDT has replaced the language with "capability to control BES Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA)". This clearly eliminates TOs who are only able to control the BES by issuing verbal instructions to field personnel. Further, the language in (5) related to Generator Operators has been modified pursuant to comments to avoid inadvertently expanding the scope for Generator Operators. The SDT is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" will be adequate to avoid expanding the Control Center scope for Generator Operators. Further,	

the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator." Regarding the recommendation to replace "monitor and control" with "monitor and control or monitor and direct action for", the SDT is concerned that the additional language may add to the confusion. The language "monitor and control" has been a part of the Control Center definition since its inception and the SDT is not aware of confusion on the part of RCs, BAs or TOPs regarding application to their facilities, whether they have the capability to operate devices via Cyber Assets (e.g., a SCADA system) or whether they instruct other entities to operate devices.	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
The current proposed definition of Control Center is very wordy. Consider creating a separate definition of data center leveraging the wording in the current proposed definition of Control Center. This may allow for better overall readability.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on responses received during the field trial, the SDT confirmed that the current Control Center definition was ambiguous as it relates to Transmission Owner Control Center and use of the undefined term "data center". The SDT believes that specifically identifying each of the five registered entities that potentially have a Control Center will lead to a more consistent understanding of the definition. With respect to the term "data center", the SDT attempted to develop a new defined term "Data Center" early in the project to differentiate between Cyber Assets used to monitor and control the BES from Cyber Assets in the field such as RTUs and data aggregators. That attempt was met with opposition from the industry during an informal comment period and subsequent drafting meetings. The SDT instead elected to eliminate the undefined term "data center" from the Control Center definition and replace it with "…and any facilities	

that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time. Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition”.

Tracy MacNicoll - Utility Services, Inc. – 4

Answer	Yes
Document Name	

Comment

The drafting team should clarify the last sentence of the core definition. Are field assets such as remote terminal units excluded from the Control Center definition? “Real-time” in 4 and 5 should be capitalized.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT agrees to modify the sentence containing the phrase “generally housed in a centralized location" to avoid ambiguity and to start the sentence with “Field assets”. In addition, the term “data aggregators” will be added as an example of a field asset for additional clarification. Front-end processors used to aggregate all data coming into an EMS are not considered to be field assets because these centrally-located Cyber Assets are required to monitor and control the BES in Real-time, whereas data aggregators in the field process only a subset of data such as multi-RTU circuits.

With respect to the recommendation to use of the term “Real-time” in the Control Center definition, the SDT believes that it is appropriate to use the capitalized term when referring to “BES company-specific Real-time reliability related tasks” in order to align with the O&P Standard use in PER-005. However, in all other cases, the SDT believes that it is appropriate to retain the lower-case term. This is because the definition from the NERC Glossary of Terms, “Present time as opposed to future time”, does not adequately account for the inherent delay associated with monitoring and control of the BES for reliable operations. To provide a better defined time horizon, BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact reliable operation of the BES within 15 minutes or the activation or exercise of the compromise. It is not intended to include dispatching field personnel to a location to perform an action due to the unpredictability of time required for personnel to travel to a location and execute instructions.

Rachel Coyne - Texas Reliability Entity, Inc. – 10

Answer	
Document Name	
Comment	

Texas RE is concerned the proposed definition of Control Center inherently scopes Control Center's down from a "location" (facilities) perspective to a "room" perspective. This could be problematic for other CIP and O&P standards such as CIP-014-2 and TOP-001-5. Texas RE recommends the definition clarify that the entire applicable facility is included, rather than simply one space within the facility.

For example, if the proposed definition were adopted, in CIP-014-2, only the Control Center "room" would need to be evaluated for potential threats and vulnerabilities of a physical attack. This leaves out other areas of that facility which should also be afforded the protections of CIP-014-2.

As a second example, if the proposed definition were adopted, in TOP-001-5, only the Control Center "room" would need to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure, which leaves out other areas of the facility that should have data exchange capabilities, such as the data center.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to use of the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.

Selene Willis - Edison International - Southern California Edison Company – 5

Answer	No
Document Name	
Comment	

"See comments submitted by the Edison Electric Institute" Comments: While EEI supports the inclusion of BES into the purpose statement, we do not support replacing the defined term "Facility" with the undefined term "resource". This change does not add any improved clarity and the term Facility should be restored in the Purpose statement.	
Likes 0	
Dislikes 0	
Response	
These comments do not appear to be applicable to the work of the 2021-03 CIP-002 drafting team.	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Scot Nairn - Bonneville Power Administration - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - 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	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

2. ***The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". This was intentional, to make clear that the BES Cyber Systems to consider differ between Control Centers and other assets such as Transmission stations and Generation resources. In alignment with Part 1 of Attachment 1, BES Cyber Systems 'used by and located at' Control Centers need to be considered. This prevents expanding from Control Centers down into field assets. With respect to other assets, it is BES Cyber Systems 'associated with' the assets that are considered. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal*****.**

Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Sunflower votes no due to our disagreement with making modifications to the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT believes that modifications to the existing Control Center definition are necessary to make it clear that a Transmission Owner may have a Control Center, where that Transmission Owner has the capability to operate or direct the operation of Transmission BES Facilities. Further, the SDT believes that language in the existing definition such as "perform the reliability tasks" and "associated data centers" are not commonly understood within the industry. The language regarding "reliability tasks" predates the retirement of the NERC Functional Model and the development of BES company-specific Real-time reliability-related tasks, which creates ambiguity on how Transmission Operators and Transmission Owners should define a "reliability task". The language regarding "associated data centers" led to questions regarding the extent to which an associated data center extends beyond the Cyber Assets that are specifically required to monitor and control the BES in Real-time. The SDT reviewed the use of the term	

Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
The proposed language does not provide additional clarification. The statement above Criteria 2.11, 2.12, and 2.13 is already at the top of Section 2 above Criteria 2.1 and is redundant with verbiage already included in each of the three criteria where it states "…that is not already included in High Impact Rating (H) above…". Recommend removing the preface and leaving Criteria 2.11, 2.12, and 2.13 as written.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT acknowledges that a portion of the proposed language above Criteria 2.11, 2.12 and 2.13 is redundant with the existing language above Criteria 2.1, specifically "Each BES Cyber System, not included in Section 1 above,". However, the SDT contends that the key difference is whether a Registered Entity must consider each BES Cyber System "used by and located at" a Control Center or each BES Cyber System "associated with" an asset other than a Control Center. The language "used by and located at" is specifically relevant to Control Centers to ensure that the impact designation does not extend from the Control Center to remote locations such as switching stations, substations, and other field assets. The SDT proposed modified language to more clearly separate sections 2 and 3 of Attachment 1 to differentiate between Control Centers and other assets.	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	

The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13: “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above,”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT acknowledges that a portion of the proposed language above Criteria 2.11, 2.12 and 2.13 is redundant with the existing language above Criteria 2.1, specifically “Each BES Cyber System, not included in Section 1 above,”. However, the SDT contends that the key difference is whether a Registered Entity must consider each BES Cyber System “used by and located at” a Control Center or each BES Cyber System “associated with” an asset other than a Control Center. The language “used by and located at” is specifically relevant to Control Centers to ensure that the impact designation does not extend from the Control Center to remote locations such as switching stations, substations, and other field assets. The SDT proposed modified language to more clearly separate sections 2 and 3 of Attachment 1 to differentiate between Control Centers and other assets.	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT acknowledges that a portion of the proposed language above Criteria 2.11, 2.12 and 2.13 is redundant with the existing language above Criteria 2.1, specifically “Each BES Cyber System, not included in Section 1 above,”. However, the SDT contends that the key difference is whether a Registered Entity must consider each BES Cyber System “used by and located at” a Control Center or each BES Cyber System “associated with” an asset other than a Control Center. The language “used by and located at” is specifically relevant to Control Centers to ensure that the impact designation does not extend from the Control Center to remote locations such as switching stations, substations, and other field assets. The SDT proposed modified language to more clearly separate sections 2 and 3 of Attachment 1 to differentiate between Control Centers and other assets.	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports NAGF's comments on this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT acknowledges that a portion of the proposed language above Criteria 2.11, 2.12 and 2.13 is redundant with the existing language above Criteria 2.1, specifically “Each BES Cyber System, not included in Section 1 above,”. However, the SDT contends that the key difference is whether a Registered Entity must consider each BES Cyber System “used by and located at” a Control Center or each BES Cyber System “associated with” an asset other than a Control Center. The language “used by and located at” is specifically relevant to Control Centers to ensure that the impact designation does not extend from the Control Center to remote locations such as switching stations, substations, and other field assets. The SDT proposed modified language to more clearly separate sections 2 and 3 of Attachment 1 to differentiate between Control Centers and other assets.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	

Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT acknowledges that a portion of the proposed language above Criteria 2.11, 2.12 and 2.13 is redundant with the existing language above Criteria 2.1, specifically “Each BES Cyber System, not included in Section 1 above,”. However, the SDT contends that the key difference is whether a Registered Entity must consider each BES Cyber System “used by and located at” a Control Center or each BES Cyber System “associated with” an asset other than a Control Center. The language “used by and located at” is specifically relevant to Control Centers to ensure that the impact designation does not extend from the Control Center to remote locations such as switching stations, substations, and other field assets. The SDT proposed modified language to more clearly separate sections 2 and 3 of Attachment 1 to differentiate between Control Centers and other assets.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT acknowledges that a portion of the proposed language above Criteria 2.11, 2.12 and 2.13 is redundant with the existing language above Criteria 2.1, specifically "Each BES Cyber System, not included in Section 1 above,". However, the SDT contends that the key difference is whether a Registered Entity must consider each BES Cyber System "used by and located at" a Control Center or each BES Cyber System "associated with" an asset other than a Control Center. The language "used by and located at" is specifically relevant to Control Centers to ensure that the impact designation does not extend from the Control Center to remote locations such as switching stations, substations, and other field assets. The SDT proposed modified language to more clearly separate sections 2 and 3 of Attachment 1 to differentiate between Control Centers and other assets.

Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. "Each Control Center or backup Control Center, not already included in High Impact Rating (H) above".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT acknowledges that a portion of the proposed language above Criteria 2.11, 2.12 and 2.13 is redundant with the existing language above Criteria 2.1, specifically "Each BES Cyber System, not included in Section 1 above,". However, the SDT contends that the key difference is whether a Registered Entity must consider each BES Cyber System "used by and located at" a Control Center or each BES Cyber System "associated with" an asset other than a Control Center. The language "used by and located at" is specifically relevant to Control Centers to ensure that the impact designation does not extend from the Control Center to remote locations such as switching stations, substations, and other field assets. The SDT proposed modified language to more clearly separate sections 2 and 3 of Attachment 1 to differentiate between Control Centers and other assets.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No

Document Name	
Comment	

We agree with the proposed preface to Criteria 2.11, 2.12, and 2.13, however feel some additions need to be made to clarify “used to perform the functional obligation of” throughout the Attachment 1 criteria.

The SAR on page 3, indicates that the language scope "perform the functional obligation of" needs clarification throughout the Attachment 1 criteria, not just IRC 2.12.

In IRC 2.11 clarification is needed for "used to perform the functional obligation". In a FERC 2017 Audit lessons learned document, which auditors have referenced, during past audits and conferences/webinars, it claims that non-BES assets are to be included in the aggregate net real power calculation. This puzzles us and others as it is unclear to how a GOP performs functional obligations for non-registered non-BES generators, which have no NERC GOP functional obligations.

The IRC 2.11 clearly states to us that you aggregate the net real power of generators for which the GOP performs functional obligations. Since non-BES generators have no functional obligations they are not to be included.

Regardless, we include non-BES generation in our IRC 2.11 calculations, even though we do not believe it is required to do so, simply because auditors have told us that we have to, based on the aforementioned 2017 FERC Audit Lessons Learned document.

We suggest that the following language be added in the aforementioned proposed preface language or at the end of IRC 2.11. "Only BES generation is to be aggregated when determining the net real power capability, non-BES generation is not to be included".

Or restate, in the aforementioned preface, that GOPs do not perform functional obligations for non-BES assets, and non-BES generation is not to be included when determining a GOPs impact rating in IRC 2.11. We realize that this may seem repetitive and/or intuitive to the SDT but, per the aforementioned 2017 Lessons Learned document, others may not have known the non-BES assets have no functional obligations. And that a GOP is not accountable to perform GOP functional obligations for a non-BES generator that has no GOP functional obligations. Consequently, GOPs do not include non-BES generation when calculating net real power in IRC 2.11.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT reviewed the SAR and agrees that addressing the language “perform the functional obligations of” throughout CIP-002 is within scope. The SDT proposed additional changes to replace each instance of the phrase “perform the functional obligations of” with specific references to the relevant Registered Entities that own or operate the Control Center. The SDT believes the proposed changes to this language are appropriate and necessary as the NERC Functional Model is no longer being actively maintained (since October 2019). Further, when combined with the revised Control Center definition, the SDT does not believe that the proposed revisions are expanding applicability with respect to any Registered Entity.	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT reviewed the SAR and agrees that addressing the language “perform the functional obligations of” throughout CIP-002 is within scope. The SDT proposed additional changes to replace each instance of the phrase “perform the functional obligations of” with specific references to the relevant Registered Entities that own or operate the Control Center. The SDT believes the proposed changes to this language are appropriate and necessary as the NERC Functional Model is no longer being actively maintained (since October 2019). Further, when combined with the revised Control Center definition, the SDT does not believe that the proposed revisions are expanding applicability with respect to any Registered Entity.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	

Please see comments by Marty Hostler, NCPA. Thanks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT reviewed the SAR and agrees that addressing the language “perform the functional obligations of” throughout CIP-002 is within scope. The SDT proposed additional changes to replace each instance of the phrase “perform the functional obligations of” with specific references to the relevant Registered Entities that own or operate the Control Center. The SDT believes the proposed changes to this language are appropriate and necessary as the NERC Functional Model is no longer being actively maintained (since October 2019). Further, when combined with the revised Control Center definition, the SDT does not believe that the proposed revisions are expanding applicability with respect to any Registered Entity.	
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	
This change helps to group Control Centers from other assets, but ACES suggests grouping Attachment 1 by registration or adding a matrix by registration to make classification easier, particularly with the potential introduction of new NERC registrations, such as IBR.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT is concerned that grouping the criteria in Attachment 1 by registration or adding a matrix by registration will be cumbersome to maintain over time, and may lead to more confusion than clarity. The SDT contends that each of the criteria in Attachment 1 should be reviewed and considered individually by each Registered Entity to determine applicability.	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	

Answer	Yes
Document Name	
Comment	

AEPC signed on to ACES comments below:

This change helps to group Control Centers from other assets, but ACES suggests grouping Attachment 1 by registration or adding a matrix by registration to make classification easier, particularly with the potential introduction of new NERC registrations, such as IBR.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT is concerned that grouping the criteria in Attachment 1 by registration or adding a matrix by registration will be cumbersome to maintain over time, and may ultimately lead to more confusion than clarity. The SDT contends that each of the criteria in Attachment 1 should be reviewed and considered individually by each Registered Entity to determine applicability.

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	Yes
Document Name	
Comment	

Buckeye supports the comments made by ACES:

This change helps to group Control Centers from other assets, but ACES suggests grouping Attachment 1 by registration or adding a matrix by registration to make classification easier, particularly with the potential introduction of new NERC registrations, such as IBR.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT is concerned that grouping the criteria in Attachment 1 by registration or adding a matrix by registration will be cumbersome to maintain over time, and may lead to more confusion than clarity. The SDT contends that each of the criteria in Attachment 1 should be reviewed and considered individually by each Registered Entity to determine applicability.	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Instead of grouping Criteria 2.11, 2.12 and 2.13 in Section 2, Tacoma Power recommends creating a new Section in CIP-002 to house these criteria. If the intent of the SDT is to have these three criteria grouped separately from the other medium impact criteria in Section 2, grouping would be served better by creating a new separate section.	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Thank you for your comment. The SDT is concerned that grouping the criteria in Attachment 1 by registration or adding a matrix by registration will be cumbersome to maintain over time, and may lead to more confusion than clarity. The SDT contends that each of the criteria in Attachment 1 should be reviewed and considered individually by each Registered Entity to determine applicability.	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

The initial scope of the 2021-03 SAR initially authorized changes to 2.12, and 2.11 and 2.13 were subsequently added. The added sentence after Criterion 2.10 does not seem to add value since there the Section 2 Medium Impact Rating already includes the "associated with" wording. We understand that the intention is to group the Control Centers from other assets. BC Hydro suggests organizing the Attachment 1 by groups to clarify the scope and application.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT acknowledges that a portion of the proposed language above Criteria 2.11, 2.12 and 2.13 is redundant with the existing language above Criteria 2.1, specifically "Each BES Cyber System, not included in Section 1 above,". However, the SDT contends that the key difference is whether a Registered Entity must consider each BES Cyber System "used by and located at" a Control Center or each BES Cyber System "associated with" an asset other than a Control Center. The language "used by and located at" is specifically relevant to Control Centers to ensure that the impact designation does not extend from the Control Center to remote locations such as switching stations, substations, and other field assets. The SDT proposed modified language to more clearly separate sections 2 and 3 of Attachment 1 to differentiate between Control Centers and other assets.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports this proposed change.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support and comments.	
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	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Insititute (EEI) for question #2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. Please see response to EEI.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. Please see response to EEI.	
Andrew Smith - APS - Arizona Public Service Co. - 5	

Answer	Yes
Document Name	
Comment	
AZPS agrees with the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with the comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. Please see response to EEI.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	

NEE supports the change and is in agreement with EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. Please see response to EEI.	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon is responding in support of EEI's response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. Please see response to EEI.	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Affirmative specifically for Criteria 2.11. Alison Mackellar on behalf of Constellation Segments 5 and 6	

Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy supports this change.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments.	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	

Thank you for your support and comments. Please see response to EEI.	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Affirmative specifically for Criteria 2.11. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute” Comments: In the project SAR, bullet 1 under the Project Scope section, the SDT was asked to “[c]larify VAR-002-4.1 Requirement R3 in regards to whether the GOP of a dispersed power resource must notify its associated TOP of a status change of a voltage controlling device on an individual generating unit, for example if a single inverter goes offline in a solar PV resource.” This change was recommended to provide uniformity between wind turbine plants with other dispersed power producing resources. We support this change and recommend the SDT include a similar reporting exception for Requirement R3 to what exists in VAR-002-4.1, Requirement R4 as proposed in both the supporting white paper for this project and the Project SAR.	

EEI also asked the SDT to remove proposed Requirement R3 language that states "in a mutually-agreed communications method", because this language serves no reliability benefits but adds unnecessary compliance obligations; i.e., the need to document that an agreement was developed, mutually agreed to and was followed.	
Likes 0	
Dislikes 0	
Response	
These comments do not appear to be applicable to the work of the 2021-03 CIP-002 drafting team.	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
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	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
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	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
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	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Standifur - Austin Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
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	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scot Nairn - Bonneville Power Administration - NA - Not Applicable - 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	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

3. ***The SDT revised CIP-002-Y Attachment 1 Criterion 2.12 based on data obtained from the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.***

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
Based on the feedback provided to Question #1 above and the comments provided during the informal commenting period of this Project 2021-03 CIP-002-Y changes in July 2023. BC Hydro maintains the position that these changes are introducing ambiguities to the Control Center definition and its application, and request to kindly address the comments provided.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT reviewed the SAR and agrees that addressing the language “perform the functional obligations of” throughout CIP-002 is within scope. The SDT proposed additional changes to replace each instance of the phrase “perform the functional obligations of” with specific references to the relevant Registered Entities. The SDT agrees with concerns regarding use of the language “capability to electronically control” and has eliminated the term “electronically” in its updated proposal. With respect to the Transmission Owner, the SDT has replaced the language with “capability to control BES Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA)”. This clearly eliminates TOs who are only able to control the BES by issuing verbal instructions to field personnel. Further, the language in (5) related to Generator Operators has been modified pursuant to comments to avoid inadvertently expanding the scope for Generator Operators. The SDT is proposing the following revision: “Generator Operator personnel who perform the	

reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	
The definition of a control center add in #4 "Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;" to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact. The following wording is suggested for 2.12 to resolve this: Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT agrees that the proposed modifications to Criterion 2.12 may create a gap for a Transmission Owner that meets any of the requirements identified in Criterion 1.3. Recognizing this gap, and also recognizing the SAR allows the SDT to	

address the language “perform the functional obligations of” throughout Attachment 1, the SDT is proposing to revise Criterion 1.3 as follows: “Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.”	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	
The definition of a control center add in #4 “Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;” to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact. The following wording is suggested for 2.12 to resolve this: Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.	
Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	
Response	
Thank you for your comments. The SDT agrees that the proposed modifications to Criterion 2.12 may create a gap for a Transmission Owner that meets any of the requirements identified in Criterion 1.3. Recognizing this gap, and also recognizing the SAR allows the SDT to	

address the language "perform the functional obligations of" throughout Attachment 1, the SDT is proposing to revise Criterion 1.3 as follows: "Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10."	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
The definition of a control center add in #4 "Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;" to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact. The following wording is suggested for 2.12 to resolve this: Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT agrees that the proposed modifications to Criterion 2.12 may create a gap for a Transmission Owner that meets any of the requirements identified in Criterion 1.3. Recognizing this gap, and also recognizing the SAR allows the SDT to	

address the language "perform the functional obligations of" throughout Attachment 1, the SDT is proposing to revise Criterion 1.3 as follows:
"Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10."

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

The definition of a control center add in #4 "Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;" to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered medium impact.

The following wording is suggested for 2.12 to resolve this:

Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SDT agrees that the proposed modifications to Criterion 2.12 may create a gap for a Transmission Owner that meets any of the requirements identified in Criterion 1.3. Recognizing this gap, and also recognizing the SAR allows the SDT to

address the language "perform the functional obligations of" throughout Attachment 1, the SDT is proposing to revise Criterion 1.3 as follows: "Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10."	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The definition of a control center add in #4 "Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;" to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact. The following wording is suggested for 2.12 to resolve this: Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT agrees that the proposed modifications to Criterion 2.12 may create a gap for a Transmission Owner that meets any of the requirements identified in Criterion 1.3. Recognizing this gap, and also recognizing the SAR allows the SDT to	

address the language "perform the functional obligations of" throughout Attachment 1, the SDT is proposing to revise Criterion 1.3 as follows: "Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10."	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
The Exclusion language in Criterion 2.12 could effectively allow up to 1499MW of generation to offset any export, especially when that generation is not within the load center. Under the current language entities with a significant aggregate weighted value several times the 6000 limit would be allowed to exclude a local system that has a "net" export less than 75MW if they have generation to offset as a negative export (import). Tacoma Power recommends removing the word "net" from the Exclusion to resolve this issue. Suggested Exclusion language: "Exclusion: BES Transmission Lines monitored and controlled by the Control Center or backup Control Center may be excluded from the "aggregate weighted value" calculation if they are part of a local system that is operated at less than 300kV, where the **export** from the local system does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The **export** is based on the hourly integrated values for the most recent 12-month period."	
Likes 2	Snohomish County PUD No. 1, 6, Liang John; LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Thank you for your comment. The SDT has considered comments received regarding the exclusion clause and is proposing modifications to address the concerns raised. Specifically, the SDT has added language such that entities with an "aggregate weighted value" that exceeds 12000, as calculated per the table provided, are not eligible for any exclusion. Further, the language "net export" has been	

replaced with "gross export" to more appropriately account for system through-flow and use of generation to offset exports. Revised language is as follows: "Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may calculate a modified "aggregate weighted value" that excludes BES Transmission Lines monitored and controlled by the Control Center or backup Control Center that are part of a single group of contiguous transmission Elements operated at less than 300kV, and where the gross export does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The gross export is based on the hourly integrated values for the most recent 12-month period."	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Claudine Bates - Black Hills Corporation - 6	
Answer	No

Document Name	
Comment	
Black Hills Corporation is in agreement with EEI's comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI's comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as	

BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI's comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from “Voltage Value of a Line” to “Voltage Value of a BES Transmission Line”. The SDT believes that this specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI’s comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from “Voltage Value of a Line” to “Voltage Value of a BES Transmission Line”. The SDT believes that this specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No

Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from “Voltage Value of a Line” to “Voltage Value of a BES Transmission Line”. The SDT believes that this specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE is in support of the comments as submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions	

to CIP-002, the SDT elected to instead modify the table header from “Voltage Value of a Line” to “Voltage Value of a BES Transmission Line”. The SDT believes that this specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon is responding in support of EEI’s response to this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from “Voltage Value of a Line” to “Voltage Value of a BES Transmission Line”. The SDT believes that this specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE supports EEI’s comments: The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently	

shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees with the comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission	

Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS does not agree with the proposed changes but does supports the comments that were submitted by EEI on behalf of their members related to the exclusion of transmission lines below 100kv except those that were identified through appendix 5C of the Rules of Procedure as BES Transmission Lines. As currently written there needs to be clarity for criteria for lines below 100kv.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from “Voltage Value of a Line” to “Voltage Value of a BES Transmission Line”. The SDT believes that this specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from “Voltage Value of a Line” to “Voltage Value of a BES Transmission Line”. The SDT believes that this specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
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 Insititute (EEI) for question #3.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from “Voltage Value of a Line” to “Voltage Value of a BES Transmission Line”. The SDT believes that this specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part	

of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
We support EEI comments on Attachment 1 Criterion 2.12.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
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	

ACES agrees with the changes, but proposes additional clarity. The SDT did a great job with the additional exception from CIP-002-6, but failed to define a “local network”. There is documentation in the technical rationale, but feel we need crystal clear guidance when potentially excluding a BES Transmission Line which potentially make a Control Center medium or low impact.

ACES’ Member Arizona G&T Cooperatives (AEPC) does not completely agree with the changes. Specifically, because the implementation of the exceptions are non-standard to the CIP-002 inclusion/exclusion process(es).

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Pursuant to the comments received regarding the lack of clarify introduced by use of the undefined term “local system”, the SDT has replaced “local system that is operated at less than 300kV” with “group of contiguous Transmission Elements that is operated at less than 300kV”. The SDT continues to believe that use of an exclusion is appropriate to recognize a subset of entities for whom the constraints associated with medium impact rating categorization are not commensurate with the risk posed to the BES should their Control Center be compromised.

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

Answer	No
Document Name	

Comment

AEPC does not completely agree with the changes. Specifically, because the implementation of the exceptions are non-standard to the CIP-002 inclusion/exclusion process(es).

AEPCs objection is very similar to ACES’ feedback below, but ACES chose to be in favor of the changes because the exception language has no impact to the original weighting from the previously passed CIP-002-6 and gave entities the flexibility to define “local network”.

ACES Feedback: ACES agrees with the changes, but proposes additional clarity. The SDT did a great job with the additional exception from CIP-002-6, but failed to define a “local network”. There is documentation in the technical rationale, but feel we need crystal clear guidance when potentially excluding a BES Transmission Line which potentially make a Control Center medium or low impact.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Pursuant to the comments received regarding the lack of clarify introduced by use of the undefined term “local system”, the SDT has replaced “local system that is operated at less than 300kV” with “group of contiguous Transmission Elements that is operated at less than 300kV”. The SDT continues to believe that use of an exclusion is appropriate to recognize a subset of entities for whom the constraints associated with medium impact rating categorization are not commensurate with the risk posed to the BES should their Control Center be compromised.	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Buckeye supports the comments made by ACES: ACES agrees with the changes, but proposes additional clarity. The SDT did a great job with the additional exception from CIP-002-6, but failed to define a “local network”. There is documentation in the technical rationale, but feel we need crystal clear guidance when potentially excluding a BES Transmission Line which potentially make a Control Center medium or low impact.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Pursuant to the comments received regarding the lack of clarify introduced by use of the undefined term “local system”, the SDT has replaced “local system that is operated at less than 300kV” with “group of contiguous Transmission Elements that is operated at less than 300kV”.	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	No
Document Name	
Comment	
NST considers the "Exclusion" language to be insufficiently clear (e.g., What is a "local system"?), and we believe the SDT should endeavor to simplify a requirement that appears to require a set of highly complex calculations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Pursuant to the comments received regarding the lack of clarify introduced by use of the undefined term “local system”, the SDT has replaced “local system that is operated at less than 300kV” with “group of contiguous Transmission Elements that is operated at less than 300kV”. The SDT has considered various alternative approaches to the exclusion clause as currently proposed, but has been unable to identify a feasible alternative. Based on comments received, the SDT has updated the exclusion clause to further restrict the entities who would be eligible for an exclusion to ensure no adverse impact on reliability of the BES.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE is concerned that the way of calculating the risk may not cover all scenarios and does not account for differences in Transmission lines. Texas RE has taken the position that that BCS used to perform the functional obligations of a Transmission Operator should remain categorized as medium impact or high impact. The risk the BCS at a Control Center poses to the reliable operation of the BES is not easily covered by counting the quantity of transmission lines operated. Two Control Centers operating the same number of transmission lines may pose very different risks to the BES. For example, if one Control Center is predominantly operating Transmission lines at substations interconnected with Generation Facilities it may pose more risk than a Control Center operating Transmission lines at substations that are not interconnected with Generation Facilities.

Texas RE proposes the following language for criterion 2.12:

Each Control Center or backup Control Center operated by a Transmission Operator or owned by a Transmission Owner.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. After reviewing the Field Test responses, the SDT believes that there are entities for which the constraints associated with medium impact rating categorization are not commensurate with the risk posed to the BES should their Control Center be compromised.

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3

Answer	Yes
Document Name	

Comment

We do not support EEI comments. Exclusions are built into the BES definition. The table used to calculated weighted value imposes the definition in the table header.

Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT agrees that the table header “Voltage Value of a BES Transmission Line” is adequately clear that only a subset of lines below 100kV that are to be considered.	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Use of the undefined term “backup” Control Center is unnecessary, versus simply utilizing the defined term "Control Center.” For clarification, for 500kV and above, add the text “automatic high impact” rather than stating “0”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT reviewed and determined that eliminating the term “backup” from Attachment 1 of CIP-002 is outside the scope of its SAR. With respect to the content of the table for BES Transmission Lines 500kV and above, the SDT believes that it is appropriate to use “0 (N/A)”. The “(N/A)” has also been added to the corresponding table in criterion 2.5 that applies to Transmission Facilities. No weight is needed for BES Transmission Lines 500kV and above because criteria 1.3 elevates the BES Cyber Assets used by and located at a Control Center that monitors and controls Transmission Facilities operated at 500kV or higher to high impact.	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group has comment on Attachment 1 Criterion 2.12 as it specifically applies to TO/TOP functions/registrations	

Likes 0	
Dislikes 0	
Response	
There is insufficient detail provided in the comment for the SDT to provide a response. The SDT requests that additional detail be provided in subsequent commenting periods in the event that there are still outstanding concerns.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	
FE has no objection to the proposed criteria.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments.	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
Yes. the proposal is ok.	
Likes 0	
Dislikes 0	

Response	
Thank you for your support and comments.	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
Please see comments by Marty Hostler, NCPA. Thanks.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments.	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments.	
Selene Willis - Edison International - Southern California Edison Company - 5	

Answer	No
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute” Comments: EEI does not support the deletion of the bulleted reporting exception for individual generating units of dispersed power producing resources made to Requirement R4. The SAR scope asked the SDT to clarify whether a similar exception should be added to Requirement R3, not delete the reporting exception already contained in Requirement R4. Moreover, there is no justification provided for removing this reporting exception. The SDT should restore the bulleted reporting exception for individual generating units of dispersed power producing resources as currently contained in VAR-002-4.1. EEI also asked the SDT to remove proposed Requirement R4 language that states “in a mutually-agreeable communications method”, because this language serves no reliability benefits but adds unnecessary compliance obligations; i.e., the need to document that an agreement was developed, mutually agreed to and was followed.	
Likes 0	
Dislikes 0	
Response	
These comments do not appear to be applicable to the work of the 2021-03 CIP-002 drafting team.	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Owens - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scot Nairn - Bonneville Power Administration - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Karen Artola - CPS Energy - 1,3,5 - Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Standifur - Austin Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
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	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	
Document Name	
Comment	
Constellation has no comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	

Answer	
Document Name	
Comment	
Constellation has no comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no comment as Criterion 2.12 applies specifically to TO/TOP registrations.	
Likes 0	
Dislikes 0	
Response	

4. *Provide any additional comments for the SDT to consider, if desired*.

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	

WEC Energy Group supports the following comment drafted by the NAGF: *"The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities."*	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."	
David Jendras Sr - Ameren - Ameren Services – 3	
Answer	
Document Name	
Comment	
Ameren supports NAGF's comments on this project	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.”

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.”	
Micah Runner - Black Hills Corporation - 1	

Answer	
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.”	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: “Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.” The SDT believes that retaining the existing language “perform the reliability tasks” for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator.”	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator	

Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."	
Claudine Bates - Black Hills Corporation - 6	
Answer	
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: "The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities."	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. Expanding the definition of Control Center for Generator Operators is not in the scope of the SAR, and is not the intention of the SDT. The SDT agrees with comments received and is proposing the following revision: "Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations." The SDT believes that retaining the existing language "perform the reliability tasks" for Generator Operators will be adequate to avoid expanding the Control Center scope for Generator Operators. Further, the SDT believes that this change will address concerns raised regarding dispersed power producing resources such as wind and solar, as these individual Facilities would not be performing the reliability tasks of a Generator Operator."	
Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	
Document Name	
Comment	
Request clarification of "BES Transmission Line". "BES" is defined as Transmission elements operated at 100 kV or higher, so "BES Transmission Line" is expected to be Transmission Lines operated at 100 kV or higher. However, the new 2.12 includes weight value below 100 kV. Please define or explain.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	

Document Name	
Comment	
The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.	
Likes 0	
Dislikes 0	
Response	
The Implementation Plan includes an effective date of the new version of the standard and a phased-in compliance date for certain assets that will be impacted by the changes in 2.12. Separately, the planned and unplanned changes section addresses timelines for assets that may change impact levels beyond the effective date and phased-in compliance date and include dates on when to come into compliance with requirements throughout the rest of the CIP Reliability Standards that trigger off of CIP-002 categorization. This section will operate similarly to those planned and unplanned sections applicable in previous CIP standards versions, as referenced in that section. For example, if a few years after the effective date and phased-in date have passed, an entity has a higher impact level due to an “unplanned change,” that entity will look to the timelines in the planned/unplanned changes section for clarity on when to apply CIP Reliability Standards requirements. To help clarify that the planned/unplanned section is different than the effective date section, the SDT made the header larger in the Implementation Plan.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	

The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months, or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come into effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.	
Likes 0	
Dislikes 0	
Response	
The Implementation Plan includes an effective date of the new version of the standard and a phased-in compliance date for certain assets that will be impacted by the changes in 2.12. Separately, the planned and unplanned changes section addresses timelines for assets that may change impact levels beyond the effective date and phased-in compliance date and include dates on when to come into compliance with requirements throughout the rest of the CIP Reliability Standards that trigger off of CIP-002 categorization. This section will operate similarly to those planned and unplanned sections applicable in previous CIP standards versions, as referenced in that section. For example, if a few years after the effective date and phased-in date have passed, an entity has a higher impact level due to an "unplanned change," that entity will look to the timelines in the planned/unplanned changes section for clarity on when to apply CIP Reliability Standards requirements. To help clarify that the planned/unplanned section is different than the effective date section, the SDT made the header larger in the Implementation Plan.	
Ben Hammer - Western Area Power Administration - 1	
Answer	
Document Name	
Comment	
The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time	

frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 0	
Dislikes 0	

Response

The Implementation Plan includes an effective date of the new version of the standard and a phased-in compliance date for certain assets that will be impacted by the changes in 2.12. Separately, the planned and unplanned changes section addresses timelines for assets that may change impact levels beyond the effective date and phased-in compliance date and include dates on when to come into compliance with requirements throughout the rest of the CIP Reliability Standards that trigger off of CIP-002 categorization. This section will operate similarly to those planned and unplanned sections applicable in previous CIP standards versions, as referenced in that section. For example, if a few years after the effective date and phased-in date have passed, an entity has a higher impact level due to an "unplanned change," that entity will look to the timelines in the planned/unplanned changes section for clarity on when to apply CIP Reliability Standards requirements. To help clarify that the planned/unplanned section is different than the effective date section, the SDT made the header larger in the Implementation Plan.

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael

Dislikes 0	

Response

The Implementation Plan includes an effective date of the new version of the standard and a phased-in compliance date for certain assets that will be impacted by the changes in 2.12. Separately, the planned and unplanned changes section addresses timelines for assets that may change impact levels beyond the effective date and phased-in compliance date and include dates on when to come into compliance with requirements throughout the rest of the CIP Reliability Standards that trigger off of CIP-002 categorization. This section will operate similarly to those planned and unplanned sections applicable in previous CIP standards versions, as referenced in that section. For example, if a few years after the effective date and phased-in date have passed, an entity has a higher impact level due to an "unplanned change," that entity will look to the timelines in the planned/unplanned changes section for clarity on when to apply CIP Reliability Standards requirements. To help clarify that the planned/unplanned section is different than the effective date section, the SDT made the header larger in the Implementation Plan.

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 MRO NSRF for question #4.

Likes 0	
Dislikes 0	

Response

The Implementation Plan includes an effective date of the new version of the standard and a phased-in compliance date for certain assets that will be impacted by the changes in 2.12. Separately, the planned and unplanned changes section addresses timelines for assets that may change impact levels beyond the effective date and phased-in compliance date and include dates on when to come into compliance with requirements throughout the rest of the CIP Reliability Standards that trigger off of CIP-002 categorization. This section will operate similarly to those planned and unplanned sections applicable in previous CIP standards versions, as referenced in that section. For example, if a few years after the effective date and phased-in date have passed, an entity has a higher impact level due to an "unplanned change," that entity will look to the timelines in the planned/unplanned changes section for clarity on when to apply CIP Reliability Standards requirements. To help clarify that the planned/unplanned section is different than the effective date section, the SDT made the header larger in the Implementation Plan.

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 0	
Dislikes 0	

Response

The Implementation Plan includes an effective date of the new version of the standard and a phased-in compliance date for certain assets that will be impacted by the changes in 2.12. Separately, the planned and unplanned changes section addresses timelines for assets that may change impact levels beyond the effective date and phased-in compliance date and include dates on when to come into compliance with requirements throughout the rest of the CIP Reliability Standards that trigger off of CIP-002 categorization. This section will operate similarly to those planned and unplanned sections applicable in previous CIP standards versions, as referenced in that section. For example, if a few years after the effective date and phased-in date have passed, an entity has a higher impact level due to an "unplanned change," that entity will look to the timelines in the planned/unplanned changes section for clarity on when to apply CIP Reliability Standards requirements. To help clarify that the planned/unplanned section is different than the effective date section, the SDT made the header larger in the Implementation Plan.

Tracy MacNicoll - Utility Services, Inc. - 4

Answer	
Document Name	
Comment	

The way **"Phased-in Implementation Date for CIP-002-Y, Requirement R1, Attachment 1 Criterion 2.12"** in the implementation plan is currently written, entities may have between 9 and 24 months following their first CIP-002-Y assessment to implement a higher impact level categorized BES Cyber System. This is due to the fact that they can perform their initial assessment up to 15 months following the Effective Date of CIP-002-Y based on when they performed their previous assessment. The drafting team should consider starting the 24-month clock once an entity performs its initial CIP-002-Y assessment, not based on the effective date of CIP-002-Y as it is currently written.

Entities that identify their first high impact or medium impact BES Cyber System, under their initial CIP-002-Y assessment, should be awarded the full 24 month compliance implementation per the last row of the table on page 4 of 5 of the Implementation Plan regardless of if they perform that assessment 1 month or 14 months following the Effective Date of CIP-002-Y.

Likes 0	
Dislikes 0	

Response

The Implementation Plan includes an effective date of the new version of the standard and a phased-in compliance date for certain assets that will be impacted by the changes in 2.12. Separately, the planned and unplanned changes section addresses timelines for assets that may change impact levels beyond the effective date and phased-in compliance date and include dates on when to come into compliance with requirements throughout the rest of the CIP Reliability Standards that trigger off of CIP-002 categorization. This section will operate similarly to those planned and unplanned sections applicable in previous CIP standards versions, as referenced in that section. For example, if a few years after the effective date and phased-in date have passed, an entity has a higher impact level due to an "unplanned change," that entity will look to the timelines in the planned/unplanned changes section for clarity on when to apply CIP Reliability Standards requirements. To help clarify that the planned/unplanned section is different than the effective date section, the SDT made the header larger in the Implementation Plan.

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	

Document Name	
Comment	
BC Hydro recognizes the effort done by this drafting team to encapsulate the changes via Project 2021-3 CIP-002-Y and look forward to the resolution of the comments and suggestions provided. Additionally with respect to the Implementation Plan there are multiple time frames allowed for the implementation period per the new changes to CIP-002-Y standard e.g., 12 months for net new BCS (high/medium) and 24 months for entities first time identified high or medium impact BCS. BC Hydro recommends that in all cases including a net new high/medium impact BCS, newly categorized high impact BCS from medium impact BCS and newly categorized medium impact BCS implementation time should be a minimum of 24 months. For instance, in cases where existing assets are newly identified as Control Centres as a result of the new Glossary and CIP-002 standard revisions which in turn results in the identification of newly categorized high impact BCS from medium impact BCS and newly categorized medium impact BCS BES Cyber Systems there should be a minimum of 24 months to comply with the breadth of applicable CIP standards. This would not be limited to only those cases that meet criterion 2.12 but other impact rating criterion explicitly associated with Control Centre BES Cyber Assets (e.g. high impact rating criterion 1.1 through 1.4, other medium impact rating criterion, and low impact rating criterion).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The 12 and 24 months have been established and the SDT does not see a need to change the implementation times for planned and unplanned changes.	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	

The SAR indicates to clarify "perform the functional obligation of " throughout the Attachment 1 criteria. See proposed clarifications in response 2 above.

If the SDT is not willing to make said clarification changes then please inform us where NERC specifically lists functional obligations associated with non-registered non-BES generation. The standard we believe already clearly states BES throughout it, but oblivious some auditors have made an interpretation that we are being subject to, and should not be subject to.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT reviewed the SAR and agrees that addressing the language "perform the functional obligations of" throughout CIP-002 is within scope. The SDT proposed additional changes to replace each instance of the phrase "perform the functional obligations of" with specific references to the relevant Registered Entities that own or operate the Control Center. The SDT believes the proposed changes to this language are appropriate and necessary as the NERC Functional Model is no longer being actively maintained (since October 2019). Further, when combined with the revised Control Center definition, the SDT does not believe that the proposed revisions are expanding applicability with respect to any Registered Entity.

Dennis Sismaet - Northern California Power Agency - 6

Answer	
Document Name	

Comment

Please see comments by Marty Hostler, NCPA. Thanks.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT reviewed the SAR and agrees that addressing the language “perform the functional obligations of” throughout CIP-002 is within scope. The SDT proposed additional changes to replace each instance of the phrase “perform the functional obligations of” with specific references to the relevant Registered Entities.	
Michael Whitney - Northern California Power Agency - 3	
Answer	
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT reviewed the SAR and agrees that addressing the language “perform the functional obligations of” throughout CIP-002 is within scope. The SDT proposed additional changes to replace each instance of the phrase “perform the functional obligations of” with specific references to the relevant Registered Entities that own or operate the Control Center. The SDT believes the proposed changes to this language are appropriate and necessary as the NERC Functional Model is no longer being actively maintained (since October 2019). Further, when combined with the revised Control Center definition, the SDT does not believe that the proposed revisions are expanding applicability with respect to any Registered Entity.	
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	

Suggest that guidance be given on the result of combining the “BES” and the “Transmission Line” NERC defined terms. While the BES term allows for Transmission lines less than 100kV the “Transmission Lines” sets a lower limit of 69kV. Request clarification for a 69 kV line that meets the Transmission Line definition but not the BES definition.

This is not specific to this question and may identify an issue that is not technically possible but there is a gap between the X99 and Y00 “Characteristics of Line” levels. A 199.5kV line is not rated on this table.

Request explicit explanation (in the Standard) of the weighted value of zero for “Each BES Transmission Line 500 kV and above.” (see Criterion 2.5) We agree with the weighted value. Please correct as needed – we understand that a Control Center with such a Tranmission Line is High Impact.

The language for the exemption seems to allow for the exclusion of a Controls Center as Medium impact if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines, even if these lines are not tied together within the Transmission system controlled by the Control Center.

Does the “net” in “net export” apply to the net total for all applicable BES Transmission Lines at a single point in time or the net export of each of these lines over the 12 month period.

The 12 month period portion of the language makes it unclear how new transmission lines are handled even if it is known that they will increase the “net export” beyond the 75MW threshold.

The SDT should provide clarity on if a change in the “net export” fluctuates around or exceeds for the first time, the 75MW threshold. When is exceeding the threshold an “unplanned change”, allowing for a 2 year implementation and when is it a “planned change” requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center looses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then looses the exemption, if there are not other medium impact programs in place, do they always get 2 year to either implement the plan or pray that they gain the exemption before the implementation period is over?

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered. Regarding the application of the table provided to a line that is nominally rated at 199.5kV, the SDT believes this to be more of a theoretical concern than a practical concern. The SDT has constructed the table similarly to the corresponding table that applies to Transmission Facilities. The SDT is not aware of any significant challenges in interpreting the existing table and believes that deviating from the established structure would create unnecessary confusion. With respect to the content of the table for BES Transmission Lines 500kV and above, the SDT believes that it is appropriate to use "0 (N/A)". The "(N/A)" has also been added to the corresponding table in criterion 2.5 that applies to Transmission Facilities. No weight is needed for BES Transmission Lines 500kV and above because criteria 1.3 elevates the BES Cyber Assets used by and located at a Control Center that monitors and controls Transmission Facilities operated at 500kV or higher to high impact. The SDT has considered comments received regarding the exclusion clause and is proposing modifications to address the concerns raised. Specifically, the SDT has added language such that entities with an "aggregate weighted value" that exceeds 12000, as calculated per the table provided, are not eligible for any exclusion. Further, the language "net export" has been replaced with "gross export" to more appropriately account for system through-flow and use of generation to offset exports. Revised language is as follows: "Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may calculate a modified "aggregated weighted value" that excludes BES Transmission Lines monitored and controlled by the Control Center or backup Control Center that are part of a single group of continuous transmission Elements operated at less than 300kV, and where the gross export does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The gross export is based on the hourly integrated values for the most recent 12-month period." The technical rationale provides additional detail regarding the exclusion clause.

Constantin Chitescu - Ontario Power Generation Inc. – 5	
Answer	
Document Name	

Comment	
OPG supports NPCC/RSC's comments.	
Likes 0	
Dislikes 0	

Response

Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from “Voltage Value of a Line” to “Voltage Value of a BES Transmission Line”. The SDT believes that this specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.

Regarding the application of the table provided to a line that is nominally rated at 199.5kV, the SDT believes this to be more of a theoretical concern than a practical concern. The SDT has constructed the table similarly to the corresponding table that applies to Transmission Facilities. The SDT is not aware of any significant challenges in interpreting the existing table and believes that deviating from the established structure would create unnecessary confusion.

With respect to the content of the table for BES Transmission Lines 500kV and above, the SDT believes that it is appropriate to use “0 (N/A)”. The “(N/A)” has also been added to the corresponding table in criterion 2.5 that applies to Transmission Facilities. No weight is needed for BES Transmission Lines 500kV and above because criteria 1.3 elevates the BES Cyber Assets used by and located at a Control Center that monitors and controls Transmission Facilities operated at 500kV or higher to high impact.

The SDT has considered comments received regarding the exclusion clause and is proposing modifications to address the concerns raised. Specifically, the SDT has added language such that entities with an “aggregate weighted value” that exceeds 12000, as calculated per the table provided, are not eligible for any exclusion. Further, the language “net export” has been replaced with “gross export” to more appropriately account for system through-flow and use of generation to offset exports. Revised language is as follows: “Provided that the “aggregate weighted value” calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may calculate a modified “aggregated weighted value” that excludes BES Transmission Lines monitored and controlled by the Control

Center or backup Control Center that are part of a single group of continuous transmission Elements operated at less than 300kV, and where the gross export does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The gross export is based on the hourly integrated values for the most recent 12-month period.” The technical rationale provides additional detail regarding the exclusion clause.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	
Document Name	
Comment	
LCRA believes that changing the definition of Control Center will have unintended consequences. This change impacts the applicability of CIP-012 and may impact additional Operations and Planning Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the “SAR Information” section under bullet “Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations”) that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	
Document Name	
Comment	

LCRA believes that changing the definition of Control Center will have unintended consequences. This change impacts the applicability of CIP-012 and may impact additional Operations and Planning Standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The portion of the 2016-02 SAR (in the "SAR Information" section under bullet "Transmission Owner (TO) Control Centers Performing Transmission Operator (TOP) Obligations") that has been assigned to the 2021-03 SDT specifically recommends clarification of the definition of Control Center. The SDT reviewed the use of the term Control Center through the NERC standards and has not identified any unintended consequences that have not been addressed in the commenting process. The SDT is committed to developing a revised Control Center definition to clarify these items without creating unintended consequences to other NERC standards.	
Kent Feliks - AEP - 3	
Answer	
Document Name	
Comment	
Understanding of the proposed revisions would be greatly enhanced by providing Implementation Guidance.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Supporting information can be found in the technical rationale.	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	
Document Name	

Comment	
This standard will burden smaller utilities (TOs) who have minimal transmission assets but who will be required to assess their system annually (every 15 months) to show their newly defined Control Centers will fall under the mathematical threshold of applicability. It will also create a path where the new definition of a Control Center may risk the small Transmission Owners' exposure to other standards regarding NERC System Operator Certification, and other related standards.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Based on the Field Test responses, the SDT agrees that there are entities for which the constraints associated with medium impact rating categorization are not commensurate with the risk posed to the BES should their Control Center be compromised. The proposed changes to the standard are intended to allow these entities to classify the BES Cyber Systems associated with their Control Centers as low impact. Without modifications to the standard, BES Cybers Systems associated with Transmission Owner Control Centers would all be classified as high impact or medium impact per the existing requirements.	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	
Document Name	
Comment	
Under the definition of a control center, please define or clarify what is consider “in real-time". Is real-time considered within 15 minutes impact, 5 minutes, or immediate?	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. With respect to the recommendation to use of the term “Real-time” in the Control Center definition, the SDT believes that it is appropriate to use the capitalized term when referring to “BES company-specific Real-time reliability related tasks” in order to align with the O&P Standard use in PER-005. However, in all other cases, the SDT believes that it is appropriate to retain the lower-case term. This is because the definition from the NERC Glossary of Terms, “Present time as opposed to future time”, does not adequately account for the inherent delay associated with monitoring and control of the BES for reliable operations. To provide a better defined time horizon, BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact reliable operation of the BES within 15 minutes or the activation or exercise of the compromise. It is not intended to include dispatching field personnel to a location to perform an action due to the unpredictability of time required for personnel to travel to a location and execute instructions.

Karen Artola - CPS Energy - 1,3,5 - Texas RE

Answer	
Document Name	

Comment

Please provide clarification on the intent of the retirement of Sections in CIP-002-5.1a labeled “Background” and “Guidelines and Technical Basis” from the CIP-002-Y proposed draft language to the Technical Rationale Project 2021-03 CIP-002 | Reliability Standard CIP-002-Y document. Especially of concern is the retirement of the concept of BES reliability operating service (BROS) from the CIP-002 Cyber Security-BES Cyber System Categorization standard entirely. The BROS is essential for the proper classification/categorization of BES Cyber Systems (BCS) and in determining the overall BES impact of those BCS. The ongoing use of the BROS in BCS categorization and BES impact rating determination may have been overlooked by the Project 2021-03 CIP-002 SDT based on the statement: "...to preserve any historical references."

Likes 0	
Dislikes 0	

Response

Thank you for your comment. SThe “Background” and “Guidelines and Technical Basis” sections of CIP-002-5.1a have been moved from the standard into the technical rationale.

Nicolas Turcotte - Hydro-Quebec (HQ) - 1

Answer	
Document Name	
Comment	
A negative vote was cast in error. We support the changes.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	

"See comments submitted by the Edison Electric Institute" While EEI does not oppose the use of the term "generator resource(s)" in place of generator, it does not add any enhanced clarity to the language of the VAR-002, noting that the term generator is well understood in the industry.	
Likes 0	
Dislikes 0	
Response	
These comments do not appear to be applicable to the work of the 2021-03 CIP-002 drafting team.	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	
Document Name	
Comment	
(No further comment)	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

No additional comments.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	
Document Name	
Comment	
Constellation has no additional comments. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	
Document Name	
Comment	
None	

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	
Document Name	
Comment	
No additioinal comments.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
ACES would like to thank the SDT for its continued hard work.	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
AEPC appreciates the opportunity to comment and appreciates the hard work by the SDT.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	

Document Name	
Comment	
Constellation has no comments. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	

***Comment submitted by** Associated Electric Cooperative, Inc.*
"The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight

of a Control Center or backup Control Center."

Response
Thank you for your comment. The SDT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Lines that is less than 100 kV could be identified as part of the Bulk Electric System. Due to concerns that future changes to the NERC Rules of Procedure would potentially trigger future revisions to CIP-002, the SDT elected to instead modify the table header from "Voltage Value of a Line" to "Voltage Value of a BES Transmission Line". The SDT believes that this specific reference to the "BES Transmission Line" in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered.

Comments submitted by SERC
Question 1

- SERC appreciates the work of the SDT on this long-running project, and has the following comments on the Control Center definition changes:
- The use of the word 'generally' in a Glossary definition lacks clarity and could lead to inconsistent application among Responsible Entities.
- It is unclear what security principle or finding from the field study/trial excludes 'field assets' such as:
    - data aggregation sites or data acquisition nodes,
    - tie line meters and their data,
    - synchophasors and their data,
    - Cyber Assets used to provide a wide area view, such as frequency monitor.
    - or other technologies such as devices used for monitoring or updating dynamic line ratings under Order 881 and their data
    - from consideration as BES Cyber Assets, since they ultimately exist to provide the information used by the Control Center and its operating personnel to reliably operate the BES. These Cyber Assets are typically not considered by other Attachment 1 criteria since while they are **located at** substations and generation Facilities, the reliability function they serve is to provide data for Control Centers. Suggest that if the SDT wishes to limit the location of BES Cyber Assets associated with Control Centers, the inclusion of' used by and located at' which is added before Attachment 1 Criterion 2.11, 2.12, and 2.13 in the CIP-002-Y draft accomplishes this.
- The phrasing requiring 'monitor and control' and the description of the exclusion of voice/radio only Control Centers would seem to eliminate most Reliability Coordinator control centers from meeting the glossary term, as RCs do monitor but do not control the BES in real-time, except primarily through the use of voice instructions and electronic communications (such as RCIS) that are excluded from this standard. While Attachment Criterion 1.1 does explicitly call on Control Centers performing the functional obligations of an RC, by the

letter of the new definition which includes ‘monitor and control’ most RCs could exclude themselves. Suggest changing ‘monitor and control' phrasing to either ‘monitor or control’ or ‘monitor and/or control’.

- The exclusion of Cyber Assets which only 'monitor' but do not 'monitor and control' does not seem to align with the goal of reliably operating the Interconnection(s), as control of Facilities without accurate monitoring data does not lead to secure and reliable operations. Suggest that instead the 'monitor and control the BES in real-me' phrasing be directed instead at Cyber Assets which either monitor or control and are used to accomplish or achieve compliance with NERC O&P standards with a real-me horizon, as described in the 1-5 numbered items in the definition. This may also eliminate some TO control centers who perform the monitoring functions of the TOP but to operate breakers at up to 500kV use interpersonal communication to member cooperative control rooms which have direct control of the 100-500kV breakers via SCADA to the RTU. There are other instances in the present time where the monitoring and control functional obligations of Transmission Operation are divided between multiple different NERC Responsible Entities and service providers, each of which provide part of the composite actions which satisfy the functional obligations of the RC, BA, TOP, and GOP during normal and emergency operations. Suggest changing ‘monitor and control' phrasing to either ‘monitor or control’ or ‘monitor and/or control’ to allow for this flexibility without risking a miss in categorizing a BES Cyber Asset/System.
- The change from facilities to 'rooms' may cause confusion or misapplication for other CIP and O&P standards which came after Version 5 such as CIP-012-1 and others in the COM, EOP, IRO, and TOP families since changing the Control Center definition will affect more than just Transmission Owners. Suggest research be done to understand if knock-on effects in complying with these standards will occur.
- The shifting case of the phrase ‘Real-time’ in Definition items 1, 2, and 3 and ‘real-time’ in definition items 4 and 5 causes confusion as to the nature of the task sit includes. Furthermore, the NERC glossary term ‘Real-time’ is Present time as opposed to future time. Is the intent of the various phrasings of real-time to indicate only actions required at the (instantaneous) present, or does it refer instead to the NERC Time Horizon of Real-Time operations of actions within one hour, especially in the domain of monitoring?
- The Control Center definition removes the “including their associated data centers”. This is a major security gap that should be corrected.

Response
Thank you for your comment. The SDT agrees that the term “generally” is insufficiently clear for inclusion in the Control Center definition. The SDT has proposed to modify the sentence containing the phrase “generally housed in a centralized location" to the following: “Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition”. The SDT disagrees that excluding field assets from the scope of the Control Center definition eliminates field assets from consideration as BES Cyber Assets. Rather, this change is intended to align the Control Center definition with the concept of Cyber Assets “used by and located at” that appears in CIP-002 which prevents expanding from Control Centers down into field assets. To the extent that a field asset is “associated with” an asset such as a Transmission station or a Generation resource, that field asset may be identified as a BES Cyber Asset and protected at the appropriate level per Attachment 1 of CIP-002.

The current Control Center definition contains the same language "monitor and control the BES in real-time", and the SDT is unaware of any ambiguity with respect to applicability to Reliability Coordinators or other registered entities besides Transmission Owners. The SDT did eliminate the reference to "electronically control" from the sections of the Control Center definition that specifically pertain to TOs and GOPs in favor of referencing SCADA control for TOs and reliability tasks of a Generator Operator for GOPs in response to other comments received.

The SDT agrees with comments received regarding the challenges introduced by the use of terms 'rooms' and 'spaces' within the Control Center definition. Pursuant to these comments, the SDT is returning to the term 'facilities' to accommodate different configurations of facilities (e.g., rooms, buildings, locations) to house workspaces for operating personnel to monitor and control the BES in Real-time and the Cyber Assets used by those personnel to monitor and control the BES in Real-time.

With respect to the recommendation to use of the term "Real-time" in the Control Center definition, the SDT believes that it is appropriate to use the capitalized term when referring to "BES company-specific Real-time reliability related tasks" in order to align with the O&P Standard use in PER-005. However, in all other cases, the SDT believes that it is appropriate to retain the lower-case term. This is because the definition from the NERC Glossary of Terms, "Present time as opposed to future time", does not adequately account for the inherent delay associated with monitoring and control of the BES for reliable operations. To provide a better-defined time horizon, BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact reliable operation of the BES within 15 minutes or the activation or exercise of the compromise. It is not intended to include dispatching field personnel to a location to perform an action due to the unpredictability of time required for personnel to travel to a location and execute instructions.

The SDT asserts that the phrase "including their associated data centers" was not removed from the definition, but was rather replaced with a specific reference to the Cyber Assets used by operating personnel to monitor and control the BES in real-time. Pursuant to other comments received, the SDT has modified the relevant section to "and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time." The SDT believes that the revised language is adequate and appropriate to ensure that an entity does not limit their Control Center to the physical location that houses their operating personnel, but also extends their Control Center to include the relevant Cyber Assets.

Question 2

No additional comments on item #2.

Question 3

SERC appreciates the work of the SDT on this long-running project, and has the following comments on the changes to the Attachment 1 criteria:

- Has the drafting team considered how an entity would demonstrate the net export during non- EEA conditions? Is this creating more burden on the entity to generate a new value? What would happen if one year this is 74 MW for a line and the following year it crosses 75 MW? Such a situation should be addressed in the implementation plan. Would the entity need to recognize thisin its annual application of CIP-002 R2 or immediately upon generation upgrades or installations that may impact the rating? (Would this be planned or unplanned?) •
- The use of the net export of 75MW utilizes slightly different criteria than the BES definition 75MVA gross nameplate rating (not net export) traditionally used for registration. What is the reasoning for the different value, and was it derived from the field study?

Response
Thank you for your comment. The SDT has considered comments received regarding the language "net export" and has replaced this with "gross export" to more appropriately account for system flow-through and use of generation to offset exports. An entity who chooses to exercise the exclusion would be required to maintain historical hourly integrated flow values of the GCTE at each connection point to the neighboring transmission system outside the GCTE boundary. The gross export is the sum of the GCTE outflows for each hour, if any. If the gross export for any hour exceeds 75 MW after the Control Center BES Cyber Cyber System had appropriately been categorized as low impact, the categorization would change to medium impact. The affected entity should review the Implementation Plan to determine the appropriate compliance action. Unless the affected entity has foreknowledge of a physical system change that would impact the low impact categorization, the 75 MW exceedance would trigger an unplanned change. The use of "gross export" not exceeding 75 MW is selected to align with pre-existing criteria including (1) the registration criteria for a Distribution Provider and (2) the registration criteria for a Generator Owner. Establishing a threshold is intended to differentiate between non-impactful load serving areas and areas that are more likely to have an impact on the interconnected BES. It was selected to be conservative and is below other established thresholds such as the reporting requirement for uncontrolled loss of firm load resulting from a BES Emergency and firm load shedding resulting from a BES Emergency as documented in EOP-004.

Question 4

SERC appreciates the work of the SDT on this long-running project, and has the following comments on the additional changes in CIP-002-Y:

- In both 4.1.2.2 and 4.2.1.2, it appears in the redline that the word "Each" was dropped from the beginning of the sentence.

- In Attachment 1, Criteria 2.1 and 2.2, the change from 'those' to 'each discrete' phrasing to address the findings of the CIP-002-5.1a appears to create confusion due to the pluralization of 'BES Cyber Systems' appearing just after. Suggest instead to remove the word 'each', so the sentences would read "the only BES Cyber Systems that meet this criterion are discrete shared BES Cyber System that could…

Response
Thank you for your comment. The SDT will review this prior to the third draft posting.

End of Report

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Reminder
Standards Announcement
Project 2021-03 CIP-002

Initial Ballots Open through November 9, 2023

Now Available

The initial ballots for **CIP-002-Y — Cyber Security — BES Cyber System Categorization** are open through **8 p.m. Eastern, Thursday, November 9, 2023**.

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 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 2021-03 CIP-002” in the Description Box.

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Standards Announcement

Project 2021-03 CIP-002

Formal Comment Period Open through November 9, 2023
Ballot Pools Forming through October 25, 2023

Now Available

A formal comment period for **CIP-002-Y — Cyber Security — BES Cyber System Categorization**, is open through **8 p.m. Eastern, Thursday, November 9, 2023**.

There are currently two drafting teams working on modifications to CIP-002-5.1a. The Project 2021-03 standard drafting team (SDT) is posting modifications as CIP-002-Y to differentiate its work from Project 2016-02 Modifications to CIP Standards (CIP-002-7).

Commenting

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

Reminder Regarding Corporate RBB Memberships

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

Ballot Pools

Ballot pools are being formed through **8 p.m. Eastern, Wednesday, October 25, 2023.** Registered Ballot Body members can join the ballot pools here.

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

Next Steps

Initial ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted October 31 – November 9, 2023.

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

For more information or assistance, contact 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 2021-03 CIP-002" 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/304)
Ballot Name: 2021-03 CIP-002 CIP-002-Y IN 1 ST
Voting Start Date: 10/31/2023 12:01:00 AM
Voting End Date: 11/9/2023 8:00:00 PM
Ballot Type: ST
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 264
Total Ballot Pool: 297
Quorum: 88.89
Quorum Established Date: 11/9/2023 11:18:39 AM
Weighted Segment Value: 32.54

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	84	1	20	0.328	41	0.672	0	12	11
Segment: 2	7	0.5	2	0.2	3	0.3	0	1	1
Segment: 3	69	1	18	0.3	42	0.7	0	5	4
Segment: 4	15	1	3	0.3	7	0.7	0	1	4
Segment: 5	73	1	19	0.352	35	0.648	0	9	10
Segment: 6	44	1	12	0.308	27	0.692	0	3	2
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.3	1	0.1	2	0.2	0	1	1
Totals:	297	5.8	75	1.887	157	3.913	0	32	33

BALLOT POOL MEMBERS

Show All entries

Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Abstain	N/A
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
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		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
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		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City of College Station	Stacy Engelmann		None	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Abstain	N/A
1	Exelon	Daniel Gacek		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Alain Mukama		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	Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Abstain	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
1	MEAG Power	David Weekley	Rebika Yitna	None	N/A
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		None	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Negative	Comments Submitted
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.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	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 Pend Oreille County	Kevin Conway		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	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
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		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
1	Xcel Energy, Inc.	Eric Barry		Negative	Third-Party Comments
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson	John Galloway	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch		Negative	Third-Party Comments
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward	Shannon Mickens	Affirmative	N/A
3	AEP	Kent Feliks		Negative	Comments Submitted
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Alan Xu		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		Affirmative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
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		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Third-Party Comments
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Third-Party Comments
3	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	Negative	Third-Party Comments
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	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		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	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Silicon Valley Power - City of Santa Clara	VAL GUZMAN		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	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	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Acciona Energy North America	Truong Le		Affirmative	N/A
5	AEP	Thomas Foltz		Negative	Comments Submitted
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	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	Comments Submitted
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		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	Christopher Siewert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
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	Helen Wang		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Third-Party Comments
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Abstain	N/A
5	Lakeland Electric	Carmen Rodriguez		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Manitoba Hydro	Kristy-Lee Young		Negative	Third-Party Comments
5	Muscatine Power and Water	Neal Nelson		Negative	Third-Party Comments
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
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	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Pine Gate Renewables	Michiko Sell		Abstain	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	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		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		None	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Clay Walker	Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		Negative	Third-Party Comments
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	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.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		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	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	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	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
10	New York State Reliability Council	Wesley Yeomans		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	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		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

Showing 1 to 297 of 297 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/304)
Ballot Name: 2021-03 CIP-002 Implementation Plan IN 1 OT
Voting Start Date: 10/31/2023 12:01:00 AM
Voting End Date: 11/9/2023 8:00:00 PM
Ballot Type: OT
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 263
Total Ballot Pool: 290
Quorum: 90.69
Quorum Established Date: 11/9/2023 11:18:27 AM
Weighted Segment Value: 42.55

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	82	1	24	0.414	34	0.586	0	15	9
Segment: 2	7	0.5	3	0.3	2	0.2	0	1	1
Segment: 3	67	1	27	0.474	30	0.526	0	8	2
Segment: 4	15	1	3	0.3	7	0.7	0	1	4
Segment: 5	72	1	23	0.434	30	0.566	0	10	9
Segment: 6	43	1	13	0.361	23	0.639	1	4	2
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	4	0.1	1	0.1	0	0	0	3	0
Totals:	290	5.6	94	2.383	126	3.217	1	42	27

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Abstain	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		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Third-Party Comments
1	City of College Station	Stacy Engelmann		None	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Third-Party Comments
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Third-Party Comments
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
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	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Alain Mukama		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	Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Muscatine Power and Water	Andrew Kurriger		Negative	Third-Party Comments
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		None	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Abstain	N/A
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.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Negative	Third-Party Comments
1	Oncor Electric Delivery	Byron Booker		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Third-Party Comments
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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 Pend Oreille County	Kevin Conway		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	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
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		Affirmative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	ISO New England, Inc.	John Pearson	John Galloway	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch		Affirmative	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward	Shannon Mickens	Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Alan Xu		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Negative	Comments Submitted
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Bonneville Power Administration	Ron Sporseen		Affirmative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Affirmative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Third-Party Comments
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Negative	Third-Party Comments
3	Muscatine Power and Water	Seth Shoemaker		Negative	Third-Party Comments
3	National Grid USA	Brian Shanahan		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Third-Party Comments
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	Abstain	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Omaha Public Power District	David Heins		Negative	Third-Party Comments
3	OTP - Otter Tail Power Company	Wendi Olson		Negative	Third-Party Comments
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	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		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	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		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		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	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	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Third-Party Comments
4	Northern California Power Agency	Marty Hostler		Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Tracy MacNicoll		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Acciona Energy North America	Truong Le		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
5	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		Affirmative	N/A
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		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	Christopher Siewert		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
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	Helen Wang		Negative	Third-Party Comments
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Dairyland Power Cooperative	Tommy Drea		Negative	Third-Party Comments
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Abstain	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Abstain	N/A
5	Lakeland Electric	Carmen Rodriguez		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Negative	Third-Party Comments
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	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Third-Party Comments
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Third-Party Comments
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Third-Party Comments
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	Third-Party Comments
5	Pine Gate Renewables	Michiko Sell		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tennessee Valley Authority	Nehtisha Rollis		Affirmative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Negative	Third-Party Comments
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	No Comment Submitted
6	Austin Energy	Imane Mrini		Negative	Comments Submitted
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Clay Walker	Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
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	Kelly Bertholet		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Muscatine Power and Water	Nicholas Burns		Negative	Third-Party Comments
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		Affirmative	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Third-Party Comments
6	Omaha Public Power District	Shonda McCain		Negative	Third-Party Comments
6	Platte River Power Authority	Sabrina Martz		Abstain	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	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Affirmative	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
6	Xcel Energy, Inc.	Steve Szablya		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Showing 1 to 290 of 290 entries

BALLOT RESULTS

Ballot Name: 2021-03 CIP-002 Non-binding Poll IN 1 NB
Voting Start Date: 10/31/2023 12:01:00 AM
Voting End Date: 11/9/2023 8:00:00 PM
Ballot Type: NB
Ballot Activity: IN
Ballot Series: 1
Total # Votes: 245
Total Ballot Pool: 278
Quorum: 88.13
Quorum Established Date: 11/9/2023 11:40:01 AM
Weighted Segment Value: 34.22

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	78	1	16	0.34	31	0.66	21	10
Segment: 2	7	0.4	2	0.2	2	0.2	2	1
Segment: 3	65	1	15	0.294	36	0.706	10	4
Segment: 4	14	1	3	0.3	7	0.7	1	3
Segment: 5	69	1	16	0.364	28	0.636	15	10
Segment: 6	41	1	11	0.379	18	0.621	7	5
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	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	4	0.2	1	0.1	1	0.1	2	0
Totals:	278	5.6	64	1.977	123	3.623	58	33

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Abstain	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Abstain	N/A
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		Negative	Comments Submitted
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Negative	Comments Submitted
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Negative	Comments Submitted
1	Black Hills Corporation	Micah Runner		Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Abstain	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Negative	Comments Submitted
1	City Utilities of Springfield, Missouri	Michael Bowman		Negative	Comments Submitted
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Negative	Comments Submitted
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
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	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis		None	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Alain Mukama		Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte		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	Gail Elliott	Abstain	N/A
1	JEA	Joseph McClung		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Abstain	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	Muscatine Power and Water	Andrew Kurriger		Negative	Comments Submitted
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		None	N/A
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Abstain	N/A
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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.	Steve Toosevich		Affirmative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Comments Submitted
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Negative	Comments Submitted
1	Oncor Electric Delivery	Byron Booker		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Negative	Comments Submitted
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Affirmative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
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 Pend Oreille County	Kevin Conway		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		None	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Negative	Comments Submitted
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		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	U.S. Bureau of Reclamation	Richard Jackson		None	N/A
1	Unisource - Tucson Electric Power Co.	Jessica Cordero		None	N/A
1	Western Area Power Administration	Ben Hammer		Negative	Comments Submitted
2	California ISO	Darcy O'Connell		Affirmative	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Negative	Comments Submitted
2	ISO New England, Inc.	John Pearson	John Galloway	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Matthew Harward	Shannon Mickens	Affirmative	N/A
3	AEP	Kent Feliks		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Negative	Comments Submitted
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
3	BC Hydro and Power Authority	Alan Xu		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		Affirmative	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Negative	Comments Submitted
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Negative	Comments Submitted
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		None	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		None	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Affirmative	N/A
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	Comments Submitted
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Abstain	N/A
3	Los Angeles Department of Water and Power	Tony Skourtas		Abstain	N/A
3	M and A Electric Power Cooperative	Stephen Pogue		Negative	Comments Submitted
3	MGE Energy - Madison Gas and Electric Co.	Ronald Bauer		Negative	Comments Submitted
3	Muscatine Power and Water	Seth Shoemaker		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Affirmative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Negative	Comments Submitted
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
3	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	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	OTP - Otter Tail Power Company	Wendi Olson		Negative	Comments Submitted
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Abstain	N/A
3	Sacramento Municipal Utility District	Nicole Looney	Tim Kelley	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Comments Submitted
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Comments Submitted
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Negative	Comments Submitted
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Negative	Comments Submitted
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Negative	Comments Submitted
4	CMS Energy - Consumers Energy Company	Aric Root		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Negative	Comments Submitted
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		None	N/A
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Tracy MacNicoll		Affirmative	N/A
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Acciona Energy North America	Truong Le		Affirmative	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		None	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		None	N/A
5	Avista - Avista Corporation	Glen Farmer		None	N/A
5	BC Hydro and Power Authority	Helen Hamilton Harding		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Christopher Siewert		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Negative	Comments Submitted
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	Helen Wang		Negative	Comments Submitted
5	Constellation	Alison MacKellar		Negative	Comments Submitted
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Negative	Comments Submitted
5	Decatur Energy Center LLC	Megan Melham		Negative	Comments Submitted
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Abstain	N/A
5	JEA	John Babik		Abstain	N/A
5	Lakeland Electric	Carmen Rodriguez		Affirmative	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Abstain	N/A
5	Lower Colorado River Authority	Teresa Krabe		Abstain	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Negative	Comments Submitted
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Affirmative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Negative	Comments Submitted
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Oglethorpe Power Corporation	Donna Johnson		Abstain	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Negative	Comments Submitted
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Negative	Comments Submitted
5	Pacific Gas and Electric Company	Frank Lee	Michael Johnson	Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		Affirmative	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	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 Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Don Cribb		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		None	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
5	Tennessee Valley Authority	Nehtisha Rollis		Abstain	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		None	N/A
5	WEC Energy Group, Inc.	Clarice Zellmer		Negative	Comments Submitted
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Abstain	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Negative	Comments Submitted
6	Black Hills Corporation	Claudine Bates		Negative	Comments Submitted
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Michael Foley		Affirmative	N/A
6	Constellation	Kimberly Turco		Negative	Comments Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
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		Affirmative	N/A
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.	Joseph OBrien		Affirmative	N/A
6	Northern California Power Agency	Dennis Sismaet		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	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
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Abstain	N/A
6	Sacramento Municipal Utility District	Charles Norton	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	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	Ron Carlsen		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Negative	Comments Submitted
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

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Standard Development Timeline

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

Description of Current Draft

This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023

Anticipated Actions	Date
45-day formal comment period with additional ballot	April 2 – May 16, 2024
Final Ballot TOCC	December 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):

Control Center - One or more facilities used by the operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time, and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time. Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition.

1) Reliability Coordinator personnel who perform the BES company-specific Real-time reliability related tasks of a Reliability Coordinator;

2) Balancing Authority personnel who perform the BES company-specific Real-time reliability-related tasks of a Balancing Authority;

3) Transmission Operator personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations;

4) Transmission Owner personnel who have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA); or

5) Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.

A. Introduction

1. **Title:** Cyber Security — Bulk Electric System (BES) Cyber System Categorization

2. **Number:** CIP-002-Y

3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. **Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. **Distribution Provider**: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. **Responsible Entities listed in 4.1 other than Distribution Providers**: All BES Facilities.

4.2.3. **Exemptions:** The following are exempt from Standard CIP-002-Y:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See “Project 2021-03 CIP-002 Implementation Plan”.

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** RAS that support the reliable operation of the BES; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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 CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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

Violation Severity Levels

R #	Violation Severity Levels (CIP-002-Y)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15

R #	Violation Severity Levels (CIP-002-Y)			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Systems, more than 10 but less than or equal to 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.
R2	The Responsible Entity did not complete its review and update for the identification	The Responsible Entity did not complete its review and update for the identification	The Responsible Entity did not complete its review and update for the identification	The Responsible Entity did not complete its review and update for the identification

R #	Violation Severity Levels (CIP-002-Y)			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1) OR The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)	required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)	required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)	required for R1 within 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
Y	TBD		

Attachment 1 – Impact Rating Criteria[1]

1. High Impact Rating (H)
Each BES Cyber System used by and located at any of the following:

1.1. Each Control Center or backup Control Center operated by a Reliability Coordinator.

1.2. Each Control Center or backup Control Center operated by a Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center operated by a Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)
Each BES Cyber System, not included in Section 1 above, associated with any equipment as described in criteria 2.1 through 2.10:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

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[1] *The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.*

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each RAS or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

Each BES Cyber System, not included in Section 1 above, used by and located at any of the Control Centers or backup Control Centers described in criteria 2.11 through 2.13:

2.11. Each Control Center or backup Control Center operated by a Generator Operator where the aggregate highest rated net Real Power capability in the preceding 12 calendar months equals or exceeds 1500 MW in a single Interconnection.

2.12. Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per BES Transmission Line” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:
Provided that the “aggregate weighted value” calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may calculate a modified “aggregate weighted value” that excludes BES Transmission Lines monitored and controlled by the Control Center or backup Control Center that are part of a single group of contiguous transmission Elements that operate at less than 300kV, and where the gross export does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The gross export is based on the hourly integrated values for the most recent 12-month period.

2.13. Each Control Center or backup Control Center operated by a Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)
BES Cyber Systems not included in Sections 1 or 2 above that are used by and located at any of the Control Centers or backup Control Centers described in criteria 3.1:

3.1. Control Centers and backup Control Centers.

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any equipment as described in criteria 3.2 through 3.6:

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS that support the reliable operation of the BES.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Standard Development Timeline

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

Description of Current Draft

This is the second~~initial~~ draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023

Anticipated Actions	Date
45-day formal comment period with additional ballot	April 2 – May 16, 2024
Final Ballot TOCC	December 2024~~2023~~
Board adoption	December 2024~~2023~~

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):

Control Center - One or more facilities used by the~~rooms where a responsible entity hosts~~ operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time, and~~as described below, including~~ any facilities~~spaces~~ that contain~~house~~ the Cyber Assets required for~~used by operating personnel to monitor and control the BES in real-time. Cyber Assets used by~~ operating personnel to monitor and control the BES in real-time. Field~~are generally housed in a centralized location and exclude field~~ assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition.

1) Reliability Coordinator~~Operating~~ personnel who perform the BES company-specific Real-time reliability -related tasks of a Reliability Coordinator;

2) Balancing Authority~~Operating~~ personnel who perform the BES company-specific Real-time reliability-related tasks of a Balancing Authority;

3) Transmission Operator~~Operating~~ personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations;

4) ~~Operating personnel of a~~ Transmission Owner personnel who have the capability to ~~electronically~~ control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA);~~in real-time;~~ or

5)~~Operating personnel of a~~ Generator Operator personnel who perform~~have~~ the reliability tasks of a Generator Operator for~~capability to electronically control~~ generation Facilities at two or more locations~~in real-time~~.

A. Introduction

1. **Title:** Cyber Security — Bulk Electric System (BES) Cyber System Categorization

2. **Number:** CIP-002-Y

3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

   4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

   4.1.1. **Balancing Authority**

   4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

   4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

   4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

   4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

   4.1.2.2. Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

   4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

   4.1.3. **Generator Operator**

   4.1.4. **Generator Owner**

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. **Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. **Distribution Provider**: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. **Responsible Entities listed in 4.1 other than Distribution Providers**:
~~All BES Facilities.~~
All BES Facilities.

4.2.3. **Exemptions:** The following are exempt from Standard CIP-002-Y:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. **Effective Dates:** See “Project 2021-03 CIP-002 ~~Transmission Owners Control Centers~~ Implementation Plan”.~~”~~

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

i. Control Centers and backup Control Centers;

ii. Transmission stations and substations;

~~**ii.**~~**iii.** Generation resources;

~~**iii.**~~**iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;

~~**iv.**~~**v.** RAS that support the reliable operation of the BES; and

~~**v.**~~**vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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 CEA may ask an entity to provide other evidence to show that it was compliant for the full-time period since the last audit.

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

   - Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
   - If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
   - The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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

Violation Severity Levels

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-Y)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Operations Planning~~	~~High~~	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent of identified BES Cyber	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category;

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-Y)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
			OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or	Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber Systems, more than 10 but less than or equal to 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or	OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-Y)			
			Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
				fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	
R2	~~Operations Planning~~	~~Lower~~	The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (R2.1) OR The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)	The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
Y	TBD		

Attachment 1 – ~~-~~Impact Rating Criteria[1]

~~*The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.*~~

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

1.1. Each Control Center or backup Control Center operated by a~~used to perform the functional obligations of the~~ Reliability Coordinator.

1.2. Each Control Center or backup Control Center operated by a~~used to perform the functional obligations of the~~ Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. Each Control Center or backup Control Center, operated by a ~~used to perform the functional obligations of the~~ Transmission Operator or owned by a Transmission Owner, for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center operated by a~~used to perform the functional obligations of the~~ Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any equipment as described in criteria 2.1 through 2.10~~of the following~~:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner

[1] *The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.*

designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each RAS or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

Each BES Cyber System, not included in Section 1 above, used by and located at any of the Control Centers or backup Control Centers described in criteria 2.11 through 2.13~~following~~:

2.11. Each Control Center or backup Control Center operated by a ~~, not already included in High Impact Rating (H) above, used to perform the functional obligations of the~~ Generator Operator where the~~for an~~ aggregate highest rated net Real Power capability in~~of~~ the preceding 12 calendar months equals~~equal to~~ or exceeds~~exceeding~~ 1500 MW in a single Interconnection.

2.12. Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner~~, that is not already included in High Impact Rating (H) above~~, with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per BES Transmission Line~~characteristic~~" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:
Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may calculate a modified "aggregate weighted value" that excludes BES Transmission Lines monitored and controlled by the Control Center or backup Control Center that~~may be excluded from the "aggregate weighted value" calculation if they~~ are part of a single group of contiguous transmission Elements that operate ~~local system that is operated~~ at less than 300kV, and where the gross~~net~~ export ~~from the local system~~ does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The gross~~net~~ export is based on the hourly integrated values for the most recent 12-month period.

2.13. Each Control Center or backup Control Center operated by a~~, not already included in High Impact Rating (H) above, used to perform the functional obligations of the~~ Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are used by and located at any of the Control Centers or backup Control Centers described in criteria 3.1: ~~associated with any of the following assets and that meet the applicability qualifications in Section 4 – Applicability, part 4.2 – Facilities, of this standard:~~

3.1. Control Centers and backup Control Centers.

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any equipment as described in criteria 3.2 through 3.6:

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS that support the reliable operation of the BES.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Standard Development Timeline

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

Description of Current Draft

This is the second draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023

Anticipated Actions	Date
45-day formal comment period with additional ballot	April 2 – May 16, 2024
Final Ballot TOCC	December 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):

Control Center - One or more facilities ~~hosting~~ used by the operating personnel described below to ~~that~~ monitor and control the Bulk Electric System (BES) in real-time~~to perform the reliability tasks~~, ~~including~~ and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time. Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition.~~their associated data centers, of:~~

1) ~~a~~ Reliability Coordinator personnel who perform the BES company-specific Real-time reliability related tasks of a Reliability Coordinator;~~,~~

2) ~~a~~ Balancing Authority personnel who perform the BES company-specific Real-time reliability-related tasks of a Balancing Authority;~~,~~

3) ~~a~~ Transmission Operator personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator for ~~t~~Transmission Facilities at two or more locations;

4) Transmission Owner personnel who have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA); or

5) ~~a~~ Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.

A. Introduction

1. **Title:** Cyber Security — Bulk Electric System (BES) Cyber System Categorization

2. **Number:** CIP-002-~~5.1a~~Y

3. **Purpose:** To identify and categorize BES Cyber Systems and their associated BES Cyber Assets for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BES Cyber Systems could have on the reliable operation of the BES. Identification and categorization of BES Cyber Systems support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. ~~Each Special Protection System or~~ Remedial Action Scheme (RAS) where the ~~Special Protection System or Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner~~Interchange Coordinator or Interchange Authority~~

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. **Facilities:** For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. **Distribution Provider**: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. ~~Each Special Protection System or Remedial Action Scheme~~RAS where the ~~Special Protection System or Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. **Responsible Entities listed in 4.1 other than Distribution Providers**:

All BES Facilities.

4.2.3. **Exemptions:** The following are exempt from Standard CIP-002-~~5.1a~~Y:

4.2.3.1. Cyber Assets at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Assets associated with communication networks and data communication links between discrete Electronic Security Perimeters.

4.2.3.3. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.4. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See "Project 2021-03 CIP-002 Implementation Plan"

~~1. **24 Months Minimum –** CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~**6. Background:**~~

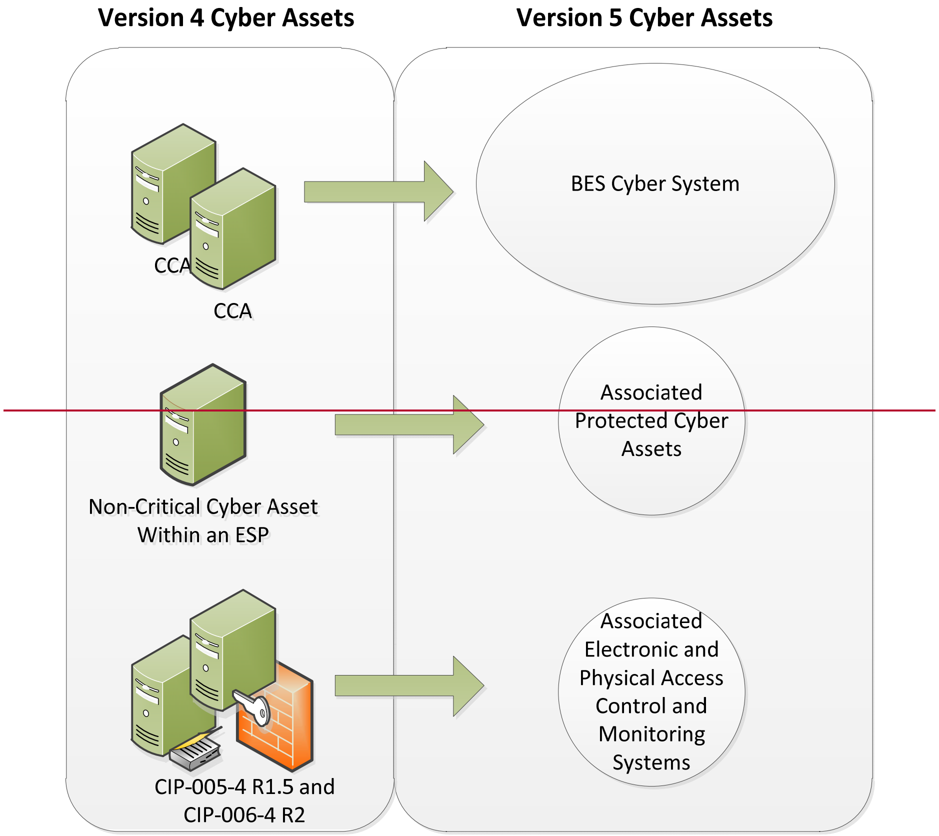
~~This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.~~

~~Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."~~

~~Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~**BES Cyber Systems**~~

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

~~Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.~~

~~It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System~~

~~boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~Reliable Operation of the BES~~

~~The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.~~

~~Real-time Operations~~

~~One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.~~

~~Categorization Criteria~~

~~The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.~~

~~This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.~~

~~**Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems**~~

~~BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:~~

~~**Electronic Access Control or Monitoring Systems ("EACMS")** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.~~

~~**Physical Access Control Systems ("PACS")**– Examples include: authentication servers, card systems, and badge control systems.~~

~~**Protected Cyber Assets ("PCA")** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.~~

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of ~~p~~Parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** ~~Special Protection Systems~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1, and Parts 1.1 and 1.2.

R2. The Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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. ~~The Regional Entity shall serve as the Compliance Enforcement Authority ("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

1.2. Evidence Retention:

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

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

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and ~~Assessment Processes~~Enforcement Program:

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

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

~~**1.4. Additional Compliance Information**~~

- ~~None~~

~~Table of Compliance Elements~~

Violation Severity Levels

R #	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets,- 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer of identified BES	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems,	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of identified BES Cyber Systems have not been

R #	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, five percent or fewer high or medium BES Cyber Systems have not been identified;	more than five percent but less than or equal to 10 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BES Cyber Systems, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than five percent but	100 high or medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent of identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BES Cyber ~~Assets~~Systems, more than 10 but less than or equal to 15 identified BES Cyber ~~Assets~~Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of	categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BES Cyber Systems, more than 15 percent of high or medium impact BES Cyber Systems have not been identified; OR

R #	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, five or fewer high or medium BES Cyber Systems have not been identified.	less than or equal to 10 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than five but less than or equal to 10 high or medium BES Cyber Systems have not been identified.	100 high and medium impact BES Cyber Systems, more than 10 percent but less than or equal to 15 percent high or medium BES Cyber Systems have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 10 but less than or equal to 15 high or medium BES Cyber Systems have not been identified.	For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BES Cyber Systems have not been identified.
R2	The Responsible Entity did not complete its review and update for the identification required for R1 within 15 calendar months but less than or equal to 16 calendar	The Responsible Entity did not complete its review and update for the identification required for R1 within 16 calendar months but less than or equal to 17 calendar	The Responsible Entity did not complete its review and update for the identification required for R1 within 17 calendar months but less than or equal to 18 calendar	The Responsible Entity did not complete its review and update for the identification required for R1 within 18 calendar months of the previous review. (R2.1)

R #	Violation Severity Levels (CIP-002-~~5.1a~~Y)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	months of the previous review. (R2.1) OR The Responsible Entity did not complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (R2.2)	months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (R2.2)	months of the previous review. (R2.1) OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (R2.2)	OR The Responsible Entity failed to complete its approval of the identifications required by R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (R2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

~~CIP-002-5.1a –~~ Attachment 1 – Impact Rating Criteria

~~**Impact Rating Criteria**~~

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High Impact Rating (H)

Each BES Cyber System used by and located at any of the following:

1.1. Each Control Center or backup Control Center ~~used to perform the functional obligations of the~~operated by a Reliability Coordinator.

1.2. Each Control Center or backup Control Center ~~used to perform the functional obligations of the~~operated by a Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. Each Control Center or backup Control Center ~~used to perform the functional obligations of the~~, operated by a Transmission Operator or owned by a Transmission Owner, for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center ~~used to perform the functional obligations of the~~operated by a Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any ~~of the~~equipment as described in ~~following~~criteria 2.1 through 2.10:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are ~~those~~each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BES Cyber Systems that meet this criterion are ~~those~~each discrete shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each ~~Special Protection System (SPS), Remedial Action Scheme (~~RAS~~),~~ or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

Each BES Cyber System, not included in Section 1 above, used by and located at any of the Control Centers or backup Control Centers described in criteria 2.11 through 2.13:

~~2.10.~~2.11. Each Control Center or backup Control Center~~, not already included in High Impact Rating (H) above, used to perform the functional obligations of the~~ operated by a Generator Operator ~~for an~~where the aggregate highest rated net Real Power capability ~~of~~in the preceding 12 calendar months equals ~~to~~ or exceed~~ing~~s 1500 MW in a single Interconnection.

2.12. Each Control Center or backup Control Center ~~used to perform the functional obligations of the~~, operated by a Transmission Operator or owned by a Transmission Owner, ~~not included in High Impact Rating (H), above.~~ with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per BES Transmission Line” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Voltage Value of a BES Transmission Line	**Weight Value per BES Transmission Line**
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:

Provided that the “aggregate weighted value” calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may calculate a modified “aggregate weighted value” that excludes BES Transmission Lines monitored and controlled by the Control Center or backup Control Center that are part of a single group of contiguous transmission Elements that operate at less than 300kV, and where the gross export does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The gross export is based on the hourly integrated values for the most recent 12-month period.

~~2.11.~~2.13. Each Control Center or backup Control Center~~, not already included in High Impact Rating (H) above, used to perform the functional obligations of the~~ operated by a Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low Impact Rating (L)

BES Cyber Systems not included in Sections 1 or 2 above that are used by and located at ~~associated with~~ any of the Control Centers or backup Control Centers described in criteria 3.1~~following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard~~:

3.1. Control Centers and backup Control Centers.

BES Cyber Systems not included in Sections 1 or 2 above that are associated with any equipment as described in criteria 3.2 through 3.6:

~~3.1.~~3.2. Transmission stations and substations.

~~3.2.~~3.3. Generation resources.

~~3.3.~~3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

~~3.4.~~3.5. ~~Special Protection Systems~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES.

~~3.5.~~3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

~~Guidelines and Technical Basis~~

~~Section 4 – Scope of Applicability of the CIP Cyber Security Standards~~

~~Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.~~

~~Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.~~

~~Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.~~

~~For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.~~

~~CIP-002-5.1a~~

~~CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."~~

~~The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber~~

~~Systems that would be subject to CIP-002-5.1a. The concept includes a number of named BES reliability operating services. These named services include:~~

~~Dynamic Response to BES conditions~~
~~Balancing Load and Generation~~
~~Controlling Frequency (Real Power)~~
~~Controlling Voltage (Reactive Power)~~
~~Managing Constraints~~
~~Monitoring & Control~~
~~Restoration of BES~~
~~Situational Awareness~~
~~Inter-Entity Real-Time Coordination and Communication~~

~~Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.~~

~~**Entity Registration**~~	~~**RC**~~	~~**BA**~~	~~**TOP**~~	~~**TO**~~	~~**DP**~~	~~**GOP**~~	~~**GO**~~
~~Dynamic Response~~		~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Balancing Load & Generation~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Controlling Frequency~~		~~X~~				~~X~~	~~X~~
~~Controlling Voltage~~			~~X~~	~~X~~	~~X~~		~~X~~
~~Managing Constraints~~	~~X~~		~~X~~			~~X~~	
~~Monitoring and Control~~			~~X~~			~~X~~	
~~Restoration~~			~~X~~			~~X~~	
~~Situation Awareness~~	~~X~~	~~X~~	~~X~~			~~X~~	
~~Inter-Entity coordination~~	~~X~~	~~X~~	~~X~~	~~X~~		~~X~~	~~X~~

~~Dynamic Response~~

~~The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:~~

- ~~Spinning reserves (contingency reserves)~~
    - ~~Providing actual reserve generation when called upon (GO,GOP)~~
    - ~~Monitoring that reserves are sufficient (BA)~~
- ~~Governor Response~~
    - ~~Control system used to actuate governor response (GO)~~
- ~~Protection Systems (transmission & generation)~~
    - ~~Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)~~
    - ~~Zone protection for breaker failure (DP, TO, TOP)~~
    - ~~Breaker protection (DP, TO, TOP)~~
    - ~~Current, frequency, speed, phase (TO,TOP, GO,GOP)~~
- ~~Special Protection Systems or Remedial Action Schemes~~
    - ~~Sensors, relays, and breakers, possibly software (DP, TO, TOP)~~
- ~~Under and Over Frequency relay protection (includes automatic load shedding)~~
    - ~~Sensors, relays & breakers (DP)~~
- ~~Under and Over Voltage relay protection (includes automatic load shedding)~~
    - ~~Sensors, relays & breakers (DP)~~
- ~~Power System Stabilizers (GO)~~

~~Balancing Load and Generation~~

~~The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:~~

- ~~Calculation of Area Control Error (ACE)~~
    - ~~Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)~~
    - ~~Software used to perform calculation (BA)~~
- ~~Demand Response~~
    - ~~Ability to identify load change need (BA)~~
    - ~~Ability to implement load changes (TOP,DP)~~
- ~~Manually Initiated Load shedding~~
    - ~~Ability to identify load change need (BA)~~
    - ~~Ability to implement load changes (TOP, DP)~~

- ~~Non-spinning reserve (contingency reserve)~~
  - ~~Know generation status, capability, ramp rate, start time (GO, BA)~~
  - ~~Start units and provide energy (GOP)~~

~~**Controlling Frequency (Real Power)**~~

~~The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:~~

- ~~Generation Control (such as AGC)~~
  - ~~ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)~~
  - ~~Software to calculate unit adjustments (BA)~~
  - ~~Transmit adjustments to individual units (GOP)~~
  - ~~Unit controls implementing adjustments (GOP)~~
- ~~Regulation (regulating reserves)~~
  - ~~Frequency source, schedule (BA)~~
  - ~~Governor control system (GO)~~

~~**Controlling Voltage (Reactive Power)**~~

~~The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:~~

- ~~Automatic Voltage Regulation (AVR)~~
  - ~~Sensors, stator control system, feedback (GO)~~
- ~~Capacitive resources~~
  - ~~Status, control (manual or auto), feedback (TOP, TO,DP)~~
- ~~Inductive resources (transformer tap changer, or inductors)~~
  - ~~Status, control (manual or auto), feedback (TOP,TO,DP)~~
- ~~Static VAR Compensators (SVC)~~
  - ~~Status, computations, control (manual or auto), feedback (TOP, TO,DP)~~

~~Managing Constraints~~

~~Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:~~

- ~~Available Transfer Capability (ATC) (TOP)~~
- ~~Interchange schedules (TOP, RC)~~
- ~~Generation re-dispatch and unit commit (GOP)~~
- ~~Identify and monitor SOL's & IROL's (TOP, RC)~~
- ~~Identify and monitor Flow gates (TOP, RC)~~

~~Monitoring and Control~~

~~Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:~~

- ~~All methods of operating breakers and switches~~
  - ~~SCADA (TOP, GOP)~~
  - ~~Substation automation (TOP)~~

~~Restoration of BES~~

~~The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:~~

- ~~Restoration including planned cranking path~~
  - ~~Through black start units (TOP, GOP)~~
  - ~~Through tie lines (TOP, GOP)~~
- ~~Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)~~
- ~~Coordination (TOP, TO, BA, RC, DP, GO, GOP)~~

~~Situational Awareness~~

~~The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:~~

- ~~Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)~~
- ~~Change management (TOP,GOP,RC,BA)~~
- ~~Current Day and Next Day planning (TOP)~~
- ~~Contingency Analysis (RC)~~
- ~~Frequency monitoring (BA, RC)~~

~~Inter-Entity Coordination~~

~~The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:~~

- ~~Scheduled interchange (BA,TOP,GOP,RC)~~
- ~~Facility operational data and status (TO, TOP, GO, GOP, RC, BA)~~
- ~~Operational directives (TOP, RC, BA)~~

~~Applicability to Distribution Providers~~

~~It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.~~

~~Requirement R1:~~

~~Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.~~

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

~~**Attachment 1**~~

~~**Overall Application**~~

~~In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.~~

- ~~When the drafting team uses the term "Facilities", there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.~~
- ~~In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.~~
- ~~It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.~~

~~**High Impact Rating (H)**~~

~~This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some~~

~~of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.~~

~~The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.~~

~~Additional thresholds as specified in the criteria apply for this category.~~

~~Medium Impact Rating (M)~~

~~Generation~~

~~The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.~~

- ~~Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.~~

  ~~In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.~~

  ~~By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.~~

~~The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.~~

- ~~In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.~~

  ~~If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.~~

  ~~The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.~~

- ~~Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2,~~ ~~**Establish and Communicate System Operating Limits**~~~~, R5.1.1 and R5.1.3.~~

  ~~IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.~~

- ~~Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.~~

- ~~Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.~~

- ~~Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~**Transmission**~~

~~*The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.*~~

- ~~Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.~~

- ~~Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.~~

~~It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.~~

- ~~Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:~~

  - ~~Excluded radial facilities that would only provide support for single generation facilities.~~

  - ~~Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.~~

~~The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.~~

~~Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:~~

- ~~230 kV –> 700 MVA~~
- ~~345 kV –> 1,300 MVA~~
- ~~500 kV –> 2,000 MVA~~
- ~~765 kV –> 3,000 MVA~~

~~In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:~~

- ~~For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate~~

~~connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.~~

- ~~Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.~~

- ~~Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.~~

~~Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.~~

1. ~~The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.~~
2. ~~The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.~~

~~The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.~~

- ~~Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2,~~ ~~**Establish and Communicate System Operating Limits**~~~~, R5.1.1 and R5.1.3.~~

- ~~Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.~~

- ~~Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.~~

- ~~Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.~~

- ~~Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.~~

  ~~This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.~~

~~The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.~~

- ~~Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.~~
- ~~Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~Low Impact Rating (L)~~

~~BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.~~

~~Restoration Facilities~~

- ~~Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.~~

  ~~In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.~~

  ~~The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.~~

~~Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.~~

~~BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.~~

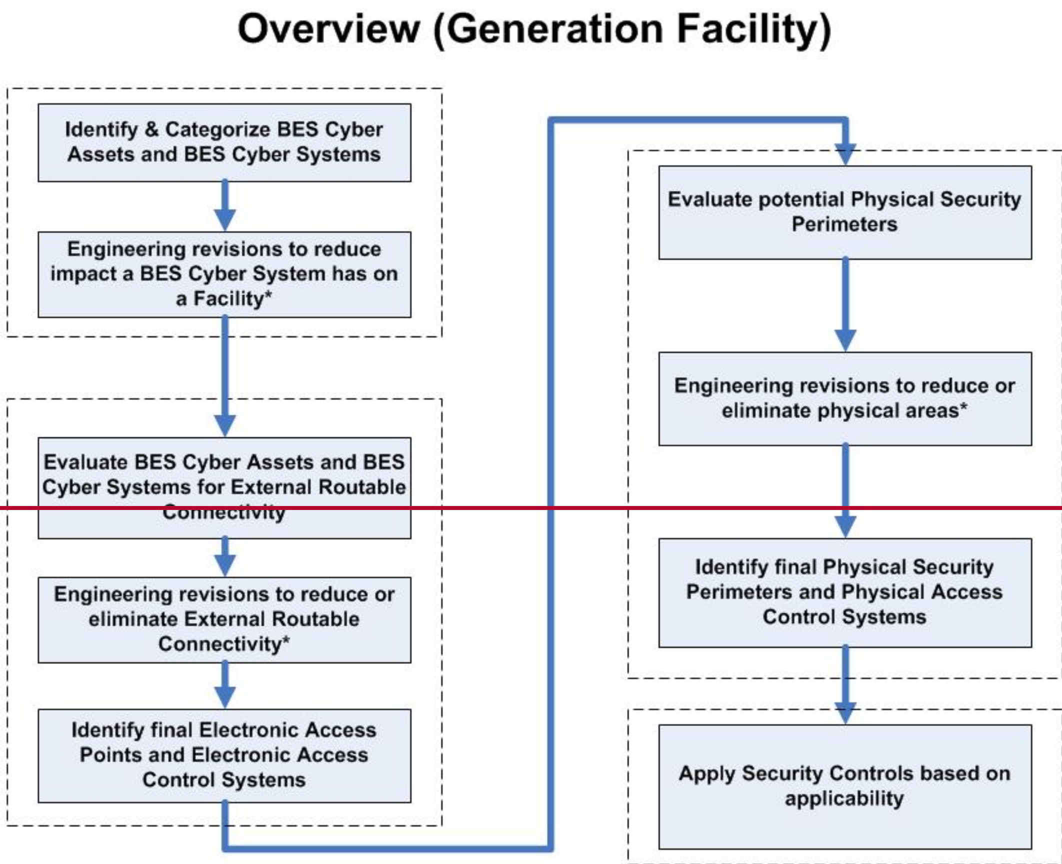
~~Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."~~

- ~~BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.~~

  ~~Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.~~

~~**Use Case: CIP Process Flow**~~

~~The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.~~



* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

~~**Rationale:**~~

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

~~**Rationale for R1:**~~

~~BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of "bright-line" criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.~~

~~**Rationale for R2:**~~

~~**The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager's approval ensures proper oversight of the process by the appropriate Responsible Entity personn**~~**Version History**

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date.	

		Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
Y	TBD		

~~Appendix 1~~

~~**Requirement Number and Text of Requirement**~~
~~CIP-002-5.1, Requirement R1~~ ~~R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:~~ ~~i. Control Centers and backup Control Centers;~~ ~~ii. Transmission stations and substations;~~ ~~iii. Generation resources;~~ ~~iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;~~ ~~v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and~~ ~~vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.~~ ~~1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;~~ ~~1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and~~ ~~1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).~~ ~~Attachment 1, Criterion 2.1~~ ~~2. Medium Impact Rating (M)~~ ~~Each BES Cyber System, not included in Section 1 above, associated with any of the following:~~ ~~2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.~~

~~Questions~~
~~Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."~~ ~~The Interpretation Drafting Team identified the following questions in the RFI:~~ ~~1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~ ~~2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~ ~~3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~
~~Responses~~
~~Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~ ~~The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)~~ ~~Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:~~ ~~The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~**Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?**~~

~~The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.~~

~~The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:~~

> ~~Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.~~

~~**Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?**~~

~~The phrase applies to each discrete BES Cyber System.~~

Implementation Plan

Project 2021-03 CIP-002 | Reliability Standard CIP-002-Y

Applicable Standard(s)

- Reliability Standard CIP-002-Y – Cyber Security - BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-5.1a – Cyber Security - BES Cyber System Categorization

Prerequisite Standard(s)

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

- None

Applicable Entities

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

Modified 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 Modified Definition(s):

Control Center - One or more facilities used by the operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time, and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time. Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition.

1) Reliability Coordinator personnel who perform the BES company-specific Real-time reliability related tasks of a Reliability Coordinator;

2) Balancing Authority personnel who perform the BES company-specific Real-time reliability-related tasks of a Balancing Authority;

3) Transmission Operator personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations;

4) Transmission Owner personnel who have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA); or

5) Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.

Background

Project 2021-03 addresses modifications to Reliability Standard CIP-002-5.1a to clarify the characterization of BES Cyber Systems associated with Control Centers used to perform the functional obligations of the Transmission Operator. Specifically, Project 2021-03 includes revisions to CIP-002 Criterion 2.12 in Attachment 1 and the Control Center definition. The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers performing the functional obligations of a Transmission Operator. These modifications resulted from recommendations from the CIP-002 Transmission Owner Control Center Field Test Report.[1]

General Considerations

This Implementation Plan includes phased-in implementation dates for Criterion 2.12 of CIP-002-Y, Attachment 1. The phased-in implementation dates allow Responsible Entities[2] a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System.

Effective Date and Phased-In Compliance Dates

The effective date for proposed Reliability Standard CIP-002-Y and the modified definition is provided below. Where the 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 of it), the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible Entities must begin to comply with that particular section of the Reliability Standard, even where the Reliability Standard goes into effect at an earlier date.

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[1] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

[2] As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

Reliability Standard CIP-002-Y and Control Center Definition

Where approval by an applicable governmental authority is required, the standard and Control Center definition shall become effective on the first day of the first calendar quarter that is three (3) 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 and Control Center definition shall become effective on the first day of the first calendar quarter that is three (3) months after the date the standard is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Dates for CIP-002-Y

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-Y, Requirement R2 within 15 calendar months of their last performance of Requirement R2 under CIP-002-5.1a.

Phased-in Implementation Date for CIP-002-Y, Requirement R1, Attachment 1 Criteria 2.12

If the revisions to Criteria 2.12 of Attachment 1 to CIP-002-Y result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as that higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP-002-Y. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a, Requirement R1, Part 1.3.

Planned or Unplanned Changes

The planned and unplanned change provisions in the Implementation Plan associated with CIP-002-5.1a shall apply to CIP-002-Y. The Implementation Plan associated with CIP-002-5.1a[3] provided as follows with respect to planned and unplanned changes (with conforming changes to the version numbers of the standard):

Planned Changes

Planned changes refer to any changes of the electric system or BES Cyber System which were planned and implemented by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-Y, Requirement R2. For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-Y, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

For planned changes resulting in a higher categorization, the Responsible Entity shall comply with

[3] The Implementation Plan associated with CIP-002-5.1a is available at https://www.nerc.com/pa/Stand/Project%20200806%20Cyber%20Security%20Order%20706%20DL/Implementation_Plan_clean_4_(2012-1024-1352).pdf.

all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section Initial Performance of Certain Periodic Requirements of the CIP-002-5.1a Implementation Plan.

Unplanned Changes

Unplanned changes refer to any changes of the electric system or BES Cyber System which were not planned by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-Y, Requirement R2.

For example, consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-Y, Attachment 1, then, later, an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-Y, Attachment 1, criteria.

For unplanned changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control and Monitoring Systems and Protected Cyber Assets, with additional time to comply for requirements in the same manner as those timelines specified in the section Initial Performance of Certain Periodic Requirements of the CIP-002-5.1a Implementation Plan.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to Medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System	12 months
Responsible Entity identifies its first high impact or medium impact BES Cyber System (i.e., the Responsible Entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002 identification and categorization processes)	24 months

Retirement Date

Reliability Standard CIP-002-5.1a

Reliability Standard CIP-002-5.1a shall be retired immediately prior to the effective date of Reliability Standard CIP-002-Y in the particular jurisdiction in which the revised standard is becoming effective.

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Unofficial Comment Form

Project 2021-03 CIP-002

Do not use this form for submitting comments. Use the Standards Balloting and Commenting System (SBS) to submit comments on **Project 2021-03 CIP-002** by **8 p.m. Eastern, Thursday, May 16, 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 2021-03 currently has five assigned Standard Authorization Requests (SARs). The proposed Standard revisions are based on the Project 2016-02 SAR which seeks to modify Reliability Standard CIP-002 to address the categorization of certain Transmission Owner Control Centers (TOCC) performing Transmission Operator (TOP) functions as medium impact based on an aggregate weighted value of their BES Transmission Lines in Criterion 2.12. The remaining four SARs will be addressed at a later date.

The Standards Committee (SC) assigned a portion of the Project 2016-02 SAR to the Project 2021-03 Standard Drafting Team (SDT) at its March 17, 2021 meeting. In addition, the SDT assisted NERC staff in meeting the directive from the NERC Board of Trustees to conduct further study of the need to readdress the applicability of the Critical Infrastructure Protection Reliability Standards to theses Control Centers to support reliability. To help meet this directive and the scope of the SAR, the SDT initiated a field test. The SC approved the Project 2021-03 Field Test Plan on November 17, 2021. Three fields tests were conducted in 2022 and the final report were posted to the project page in January 2023.

Summary of changes Overview

The SDT reviewed all comments and made modifications to the Reliability Standard and Control Center Definition accordingly. The most extensive changes were made to CIP-002 regarding the functional obligation language throughout the attachment 1 which has been replaced with specific references to Control Centers that are either operated by or owned by the relevant Registered Entities. For a detailed explanation of these changes, please refer to the *CIP-002-Y Technical Rationale*.

There are currently two drafting teams working on modifications to CIP-002-5.1a. The Project 2021-03 SDT is posting its modifications as CIP-002-Y to differentiate its work from Project 2016-02 Modifications to CIP Standards, which has posted CIP-002-7.

In addition, the proposed revised 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 revised definition used in the standard.

Questions

1. Based on industry comments, the SDT has modified the Control Center definition. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

2. Language throughout Attachment 1 of CIP-002-Y that referred to the "functional obligations" of the different Registered Entities has been replaced with specific references to Control Centers that are either operated by or owned by the relevant Registered Entities. This change was incorporated given that the NERC Functional Model is no longer being actively maintained. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal. Does the change introduce reliability gaps to the Registered Entities? If it does, please provide your rationale.

   ☐ Yes
   ☐ No

   Comments:

3. The SDT intentionally constructed the exclusion clause within criteria 2.12 of Attachment 1 of CIP-002-Y to require an entity to measure gross export from their defined group of contiguous transmission Elements (GCTE). This accounts for both generation output and flow-through the GCTE. It ensures that an entity is unable to define a GCTE that contains significant generation that supports the BES or with significant flow-through that impacts the BES. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

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

   Comments:

Technical Rationale

Project 2021-03 CIP-002

Control Center Definition and CIP-002-Y– Cyber Security – Bulk Electric System (BES) Cyber System Categorization

Introduction

This document explains the technical rationale and justification for the proposed revisions to the Control Center Definition and Reliability Standard CIP-002-Y. It provides stakeholders and the ERO Enterprise with a description of the technical requirements in the Reliability Standard. These are not Reliability Standards and should not be considered mandatory and enforceable.

Updates to this document include the Project 2021-03 CIP-002 Standards Drafting Team's (SDT's) intent in drafting changes to the requirements and definition.

Overview

Project 2021-03 proposes revisions to the Control Center definition and CIP-002-Y Criterion 2.12 in Attachment 1. CIP-002-Y provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the BES. The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers (TOCCs) performing the functional obligations of a Transmission Operator, specifically those that meet medium impact criteria, and clarifying the language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.

Rationale for Control Center Definition Modifications

Rationale for Proposing Modifications to the Control Center Definition

During the CIP-002 TOCC Field Test[1], it was found that many Transmission Owners struggled with how to interpret the Control Center definition. While the current Control Center definition does not specifically identify Transmission Owners, a Transmission Owner may have a Control Center through its ability to monitor and control the BES in real-time to perform the reliability tasks of a Transmission Operator.

This struggle surfaced in the following three manners:

- Lack of a common understanding of the term "control" versus "authority."
- Lack of a common understanding of the term "perform the functional obligations of the Transmission Operator" as stated in Attachment 1 of CIP-002-5.1a.
- Lack of a common understanding of the term "associated data centers."

Modifications to the definition have been proposed to eliminate ambiguity.

[1] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

Applicable Control Center Entities

The revised Control Center definition is structured to explicitly identify the five different types of registered entities that could have a Control Center.

Per the Control Center definition, any facilities used by operating personnel to monitor and control the BES in Real-time are considered to be part of the Control Center. Further, any facilities that contain Cyber Assets required for operating personnel to monitor and control the BES in Real-time are considered to be part of the Control Center, whether they are co-located or separately located from the physical location of the operating personnel. Entities are individually responsible for identifying the Cyber Assets that are required for their operating personnel to monitor and control the BES in Real-time.

For Reliability Coordinator, Balancing Authority and Transmission Operator entities, the operating personnel are specifically identified as those individuals who perform BES company-specific Real-time reliability-related tasks. These three entities are required to identify BES company-specific Real-time reliability-related tasks in accordance with PER-005.

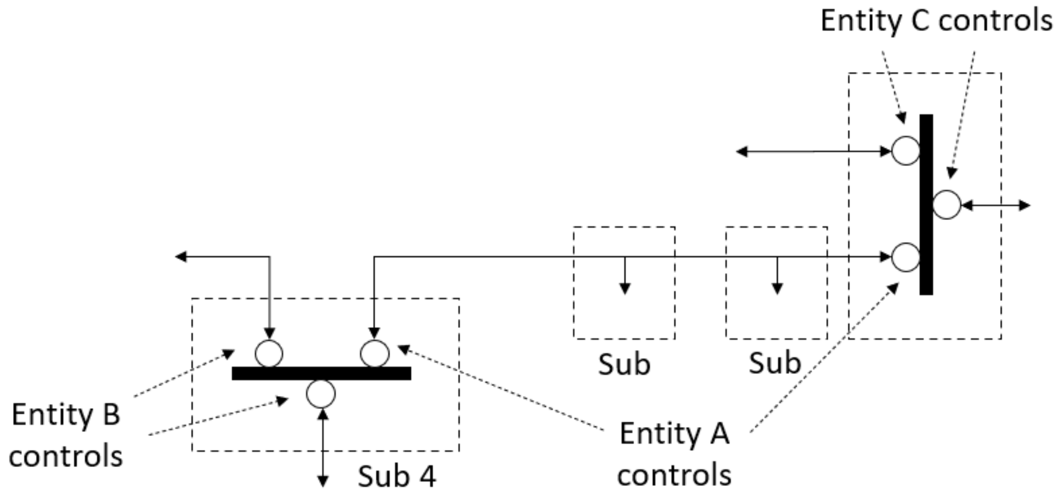
For Transmission Owner entities, operating personnel are identified as those personnel who have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA). The concept of ‘capability to control using SCADA’ is specifically used to clarify that a facility used by a Transmission Owner that monitors Facilities without any capability to electronically control those Facilities using a SCADA system does not fall within the Control Center definition. Field switching personnel are specifically excluded from being considered operating personnel.

For Generator Operator entities, operating personnel are identified as those personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations in Real-time. This language aligns with the present GOP Control Center definition. Reliability tasks may be those developed in PER-005 and PER-006.

When considering the language “Transmission Facilities at two or more locations” and “generation Facilities at two or more locations,” it is generally expected that the Facilities will have separate street addresses. Facilities located at a single street address would be associated with a single location. An entity must have more than one Facility and must have Facilities at two or more locations in order to have “Transmission Facilities at two or more locations” or “generation Facilities at two or more locations.”

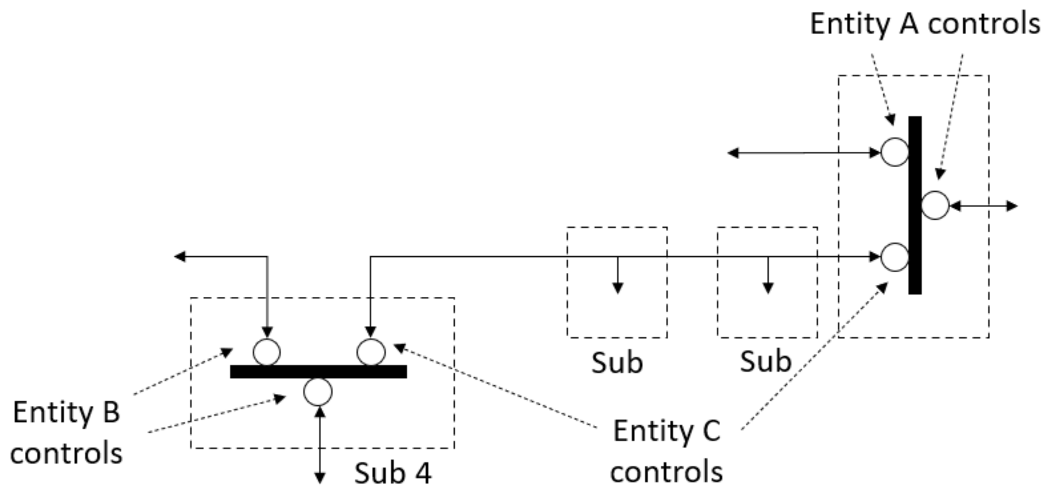
The following examples differentiate between a single Transmission Facility and two or more Transmission Facilities at one location.

Example 1

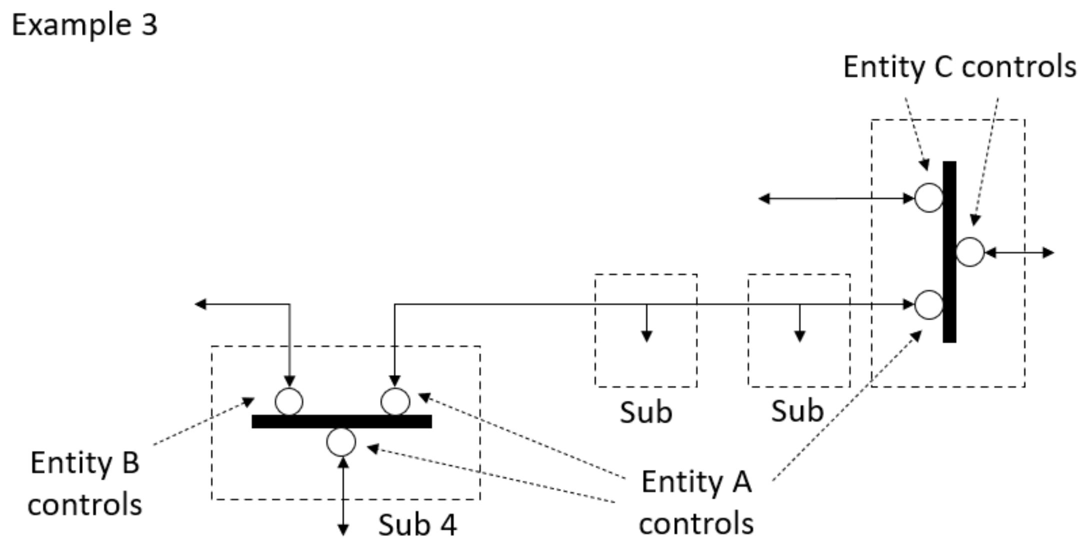


In Example 1, Entity A has control of breakers at both lines of a Transmission Line, which constitutes a Transmission Facility. Because Entity A controls a single Transmission Facility at 2 locations, Entity A does not meet the TO or TOP Control Center definition.

Example 2



In Example 2, Entity A has control of breakers at one end of two Transmission Facilities, but at a single location. Because Entity A controls two Transmission Facilities at only 1 location, Entity A does not meet the TO or TOP Control Center definition.



In Example 3, Entity A has control of breakers at one end of two Transmission Facilities and a breaker at different location. Because Entity A controls two Transmission Facilities at 2 locations, Entity A does meet the TO or TOP Control Center definition.

Associated Data Centers

The present Control Center definition includes the phrase “associated data centers”. This phrasing was originally intended to ensure the Cyber Assets not co-located in the facilities that host operating personnel are included in the Control Center definition and thus are included in the process of identifying and categorizing BES Cyber Systems.

With the lack of a NERC definition for data center and a wide variety of interpretations, the term “associated data centers” either needed to be defined or needed to be replaced with language that describes the facilities that contain Cyber Assets that need to be included in the Control Center definition. The phrase “facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time” was developed to replace “associated data center.”

A facility that contains the Cyber Assets required for operating personnel to monitor and control the BES in Real-time may be:

- located in the same room that houses operating personnel.
- located in a room that does not house operating personnel, but is in the same building as a room that houses operating personnel (shared street address).
- located in a separate building from any rooms that house operating personnel.

Language was added to the definition to specifically state that field assets (e.g., remote terminal units and data aggregators that are used to gather and communicate data to the Control Center) are excluded from the scope of the Control Center definition. RTUs and data aggregation assets would be evaluated for Cyber Security requirements based on their location and the data that they are gathering.

Cyber Assets versus Cyber Systems

The present Control Center definition refers to Cyber Assets, which is inclusive of hardware. There is no room for virtualization, such as a cloud environment, within this term. A separate drafting team 2016-02 is working to define a new term “Cyber System.” Incorporating the new term into the Control Center definition would expand the scope from Cyber Assets to include Virtual Cyber Assets and Shared Cyber Infrastructure. Depending on timing of these two efforts, there may need to be a future effort to update the Control Center definition to accommodate the expanded scope.

Rationale for General CIP-002-Y Attachment 1 Modifications

Rationale for Language to Differentiate Between Control Centers and Other Assets

Preface language has been incorporated into Sections 2 and 3 of Attachment 1 of CIP-002-Y. This language specifically applies to the criteria that are relevant to Control Centers. It essentially replaces the concept of “BES Cyber Systems … associated with” with “BES Cyber Systems … used by and located at” for Control Centers. This was intentional to make clear that the BES Cyber Systems to consider differ between Control Centers and other assets such as Transmission stations and Generation resources. In alignment with the present Part 1 of Attachment 1, BES Cyber Systems “used by and located at” Control Centers need to be considered. This prevents expanding from Control Centers down into field assets. With respect to other assets, it is BES Cyber Systems “associated with” those assets that are considered.

Rationale for Removal of Functional Obligation Language

Language throughout Attachment 1 of CIP-002-Y that referred to the “functional obligations” of the different Registered Entities has been replaced with specific references to Control Centers that are either operated by or owned by the relevant Registered Entities. This change was incorporated given that the NERC Functional Model is no longer being actively maintained. An additional challenge created by the “functional obligations” language is that, as currently written, an entity may be identified as performing functional obligations even though that entity is not currently registered with NERC. The proposed modifications ensure that the responsibility for entity registration precedes enforcement of CIP-002.

Rationale for CIP-002-Y Attachment 1 Criterion 2.12 Modifications

Aggregate Weighted Value

The total aggregate weighted value is used to account for the impact on the BES. The 6,000 aggregate weighted value threshold defined in criterion 2.12 provides sufficient differentiation for medium and low impact BES Cyber Systems associated with Control Centers that are operated by a registered Transmission Operator or owned by a registered Transmission Owner. SDT analysis of data obtained from the CIP-002 Transmission Owner Control Center Field Test[2] validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

The total aggregate weighted value of 6,000 was derived based on an entity with no single station or substation that meets criterion 2.5, but who has the capability or authority to control BES Transmission Lines with the equivalent weight of two stations or substations whose BES Cyber Systems would be classified as medium impact per criterion 2.5.

[2] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

This is ultimately derived from the “two or more locations” criteria that is documented in the Control Center definition.

The weight values per BES Transmission Line were selected to align with the process that was originally used to establish the weight values per line for criterion 2.5. For BES Transmission Lines 200 kV to 299 kV and for BES Transmission Lines 300 kV to 499 kV, the weight values per line of 700 and 1300, respectively, were retained for consistency with criterion 2.5.

Similar average MVA line loadings based on kV rating were calculated for BES Transmission Lines less than 100 kV and for BES Transmission Lines 100 kV to 199 kV using Appendix A of NERC’s Severity Risk Index Enhancements Report which result in values of 100 and 250, respectively.

BES Transmission Lines that are energized at voltages of 500 kV and above have no contribution to the aggregated weighted value given that criterion 2.4 already includes BES Cyber Systems for any Transmission Facilities at substations that are operated at 500 kV or higher as medium impact. Further, criterion 1.3 includes the BES Cyber Systems used by and located at Control Centers or backup Control Centers that monitor and control any BES Transmission Lines at substations that are operated at 500 kV or higher as high impact. The drafting team has received many inquiries into the use of 0 in the table for criterion 2.12. In an effort to proactively address the potential confusion, the drafting team has added “N/A” to the tables in criterion 2.5 and 2.12. This maintains alignment between the tables in criterion 2.5 and criterion 2.12.

For the purpose of identifying a Responsible Entity’s BES Transmission Lines, a Transmission Line is typically defined by the Protection System(s) that would be used to isolate faults on the Transmission Line which is generally defined by a boundary of fault interrupting devices (e.g., breakers) that are controlled by the line’s Protection System(s). Transmission Lines can be single-ended, two-ended or three-ended.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages less than 100 kV that are monitored and controlled by a Control Center, and that have been specifically designated as part of the BES via the NERC Rules of Procedure Exception Process.
- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV that are monitored and controlled by a Control Center, including BES Transmission Lines that connect to neighboring entities.

- Multiple-point BES Transmission Lines (e.g., two-ended or three-ended lines) are considered to contribute a single weight value per line. For any fault on the line, all line breakers located at the terminals are expected to operate to clear the fault. For example, a single 230 kV three-ended line would contribute an aggregate weighted value of 700.

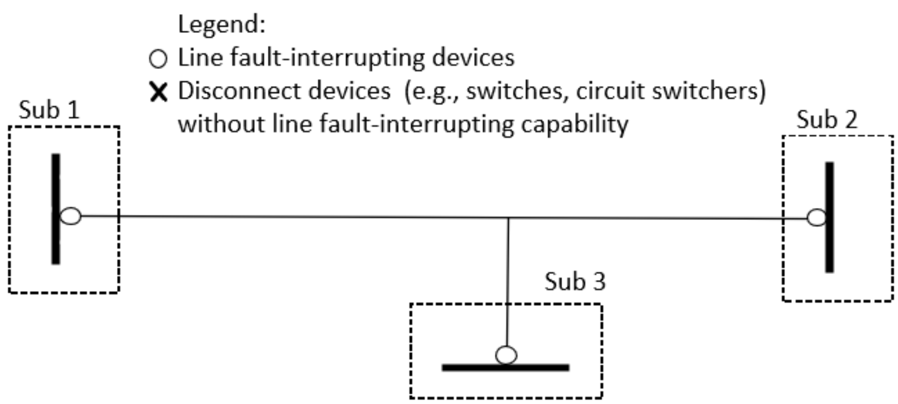


Figure 1: A 230 kV three-terminal Transmission Line contributes an aggregate weighted value of 700

- Multiple-taps BES Transmission Lines (including various implementations such as loop-in-loop-out) are considered to contribute a single weight value per line. For example, a two-ended 230 kV that has two substations tapped on the line where the substations do not have any 230 kV line fault-interrupting devices would contribute an aggregate weighted value of 700.

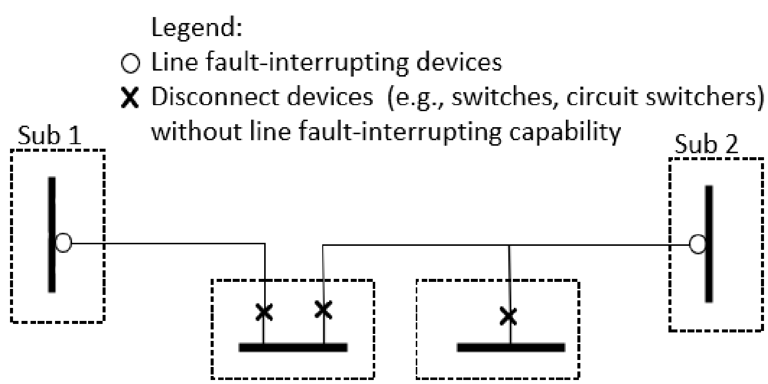


Figure 2: A 230 kV two-terminal Transmission Line with two tapped substations contributes an aggregate weighted value of 700

- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line. For example, two two-ended 345 kV lines that connect between the same two Transmission stations or substations would contribute an aggregate weighted value of 2,600.

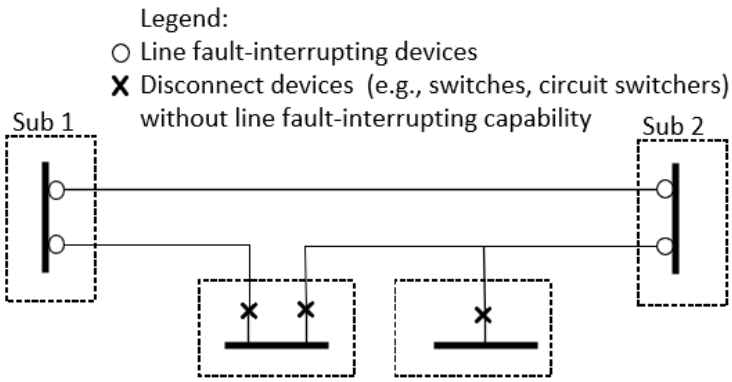


Figure 3: Two 345 kV two-terminal Transmission Lines that connect between the same two Transmission stations or substations contribute an aggregate weighted value of 2,600

Exclusion Clause

The exclusion clause applies to Transmission Operators and Transmission Owners (TOP/TO) where the initial calculated aggregated weighted value (AWV) is less than 12,000. In such cases, the TOP/TO may define a group of contiguous transmission Elements (GCTE) operated at less than 300 kV, where the gross export from the GCTE does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The purpose of the exclusion clause is to allow for a Responsible Entity to exclude BES Transmission Lines within a single local system from the AWV calculation if the gross export from the GCTE does not exceed 75 MW during non-EEA conditions. This allows for categorization at an appropriate level commensurate with the associated risk for local systems having limited flow-through or generation export and are primarily designed to serve load.

An entity is responsible to clearly define the GCTE and to monitor flows across the interfacing equipment in order to demonstrate compliance with CIP-002. Interfacing equipment is not limited to BES Transmission Lines, provided that the entity is able to collect the necessary data to demonstrate gross export from the GCTE remains below 75 MW. The GCTE may contain Elements that the Control Center is not able to control, provided that the GCTE boundary encompasses a transmission network that is primarily designed to serve load. The GCTE specifically excludes Transmission Lines 300kV and above, as they are generally intended for the bulk transfer of power and not for local load serving purposes. A restriction to allow the responsible entity to define only one GCTE is established to prohibit the ability of the entity to segment off multiple areas within a larger geographic area.

An initial calculated AWV of 12,000 is established to avoid application of the exclusion to large control areas. The AWV of 12,000 corresponds to an entity with no single station or substation that meets criterion 2.5, but who has the capability or authority to control BES Transmission Lines with the equivalent weight of four stations or substations whose BES Cyber Systems would be classified as medium impact per criterion 2.5. During the Field Test performed by the SDT entities with AWV between 500 and 11,300 were evaluated and no reliability risks to the BES were identified for any entities.

The bright line of 75 MW is selected to align with pre-existing criteria including (1) the registration criteria for a Distribution Provider and (2) the registration criteria for a Generator Owner. Establishing a threshold is intended to differentiate between non-impactful load serving areas and areas that are more likely to have an impact on the interconnected BES. It was selected to be conservative and is below other established thresholds such as the reporting requirement for uncontrolled loss of firm load resulting from a BES Emergency and firm load shedding resulting from a BES Emergency as documented in EOP-004. EEA conditions were specifically excluded to ensure a Responsible Entity is not disincentivized from providing all available assistance during emergency conditions due to future compliance considerations.

The SDT has intentionally constructed the exclusion clause to require an entity to measure gross export from their defined GCTE. This accounts for both generation output and flow-through the GCTE. It ensures that an entity is unable to define a GCTE that contains significant generation that supports the BES or with significant flow-through that impacts the BES.

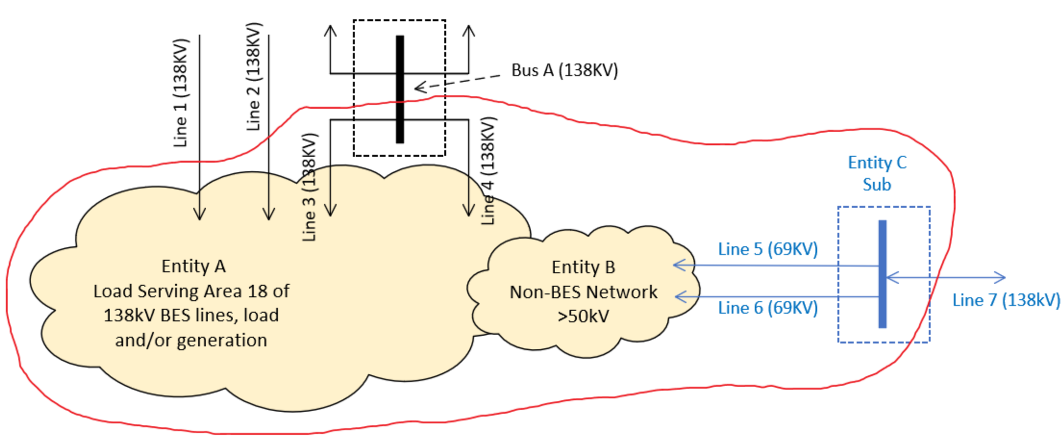
GCTE Example

The GCTE must be a contiguous system. It may contain non-BES assets that are operated above 50kV and it may contain assets owned/operated by another entity.

In this example, Entity A defines a GCTE that contains all equipment shown in the red circle below. The GCTE interface consists of the flow through Bus A, Line 1, Line 2, Line 7. The GCTE contains equipment owned and operated by Entities A, B and C. In order to demonstrate compliance with the exclusion clause, Entity A must be able to obtain the necessary data from Entity C for Line 7 to calculate the gross export to demonstrate compliance with CIP-002. The entity must also be able to determine the relevant flow through Bus A in order to demonstrate that gross export from the GCTE does not exceed 75 MW.

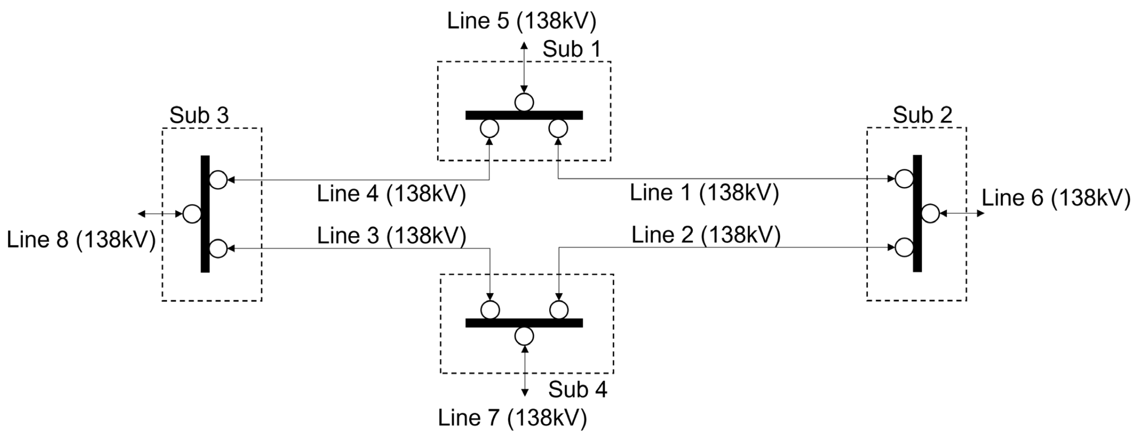
Further, it is acceptable for the GCTE to include non-BES elements that are operated above 50kV. In the event that a non-BES element is part of the GCTE interface, it will need to be included in the gross export calculation.

Typical flow on Line 7 is into this load serving system; however, during emergency conditions flow may reverse on this line. The worst non-EEA cases must be considered to verify that the 75 MW limit in the exclusion clause applies.



Example 1: Aggregate Weighted Value below 6,000

In example 1 below, BES Cyber System(s) are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



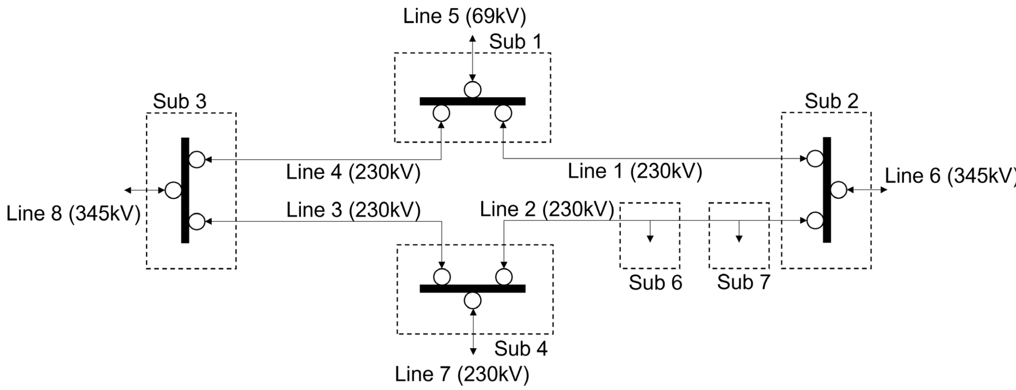
Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2,000, which is below the minimum threshold for the medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6 Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Example 2: Aggregate Weighted Value exceeds 6,000 with no Exception

In example 2 below, BES Cyber System(s) are associated with a Control Center that monitors and controls seven BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12 and sum the weighted values for each BES Transmission Line.



Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6,100, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity would be eligible to consider calculating a modified aggregate weighted value that excludes a single group of contiguous transmission Elements (GCTE) in accordance with the exclusion clause; however, in this example, the Responsible Entity either did not choose to pursue an exception or did not meet the exclusion criteria. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

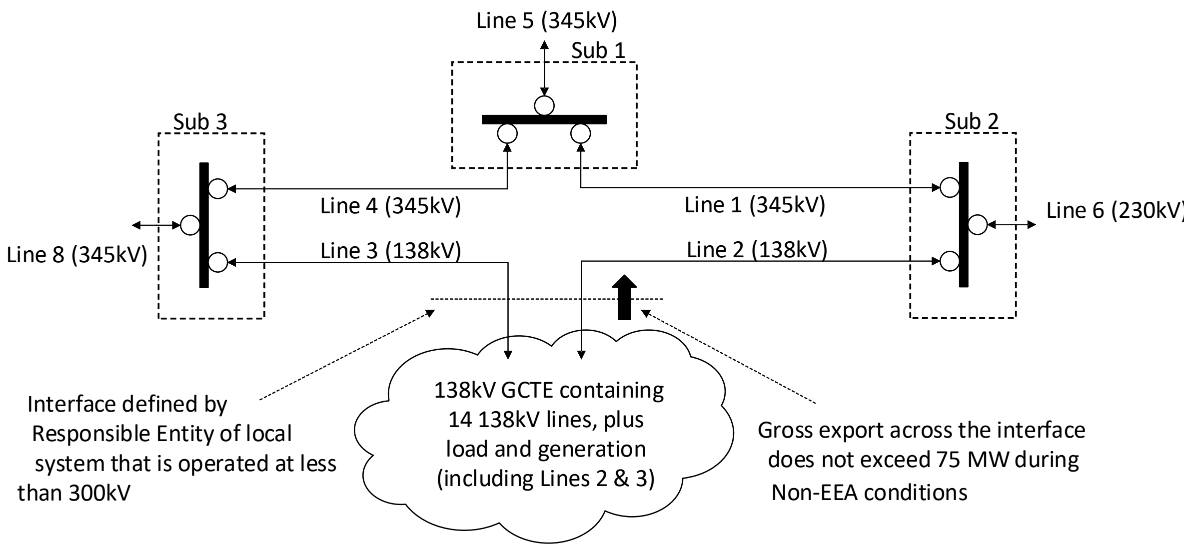
The circles on the diagram indicate the presence of fault-interrupting devices. There are two substations shown (Sub 6 and Sub 7) that are tapped on Line 2 for load serving purposes; however, these substations do not have line fault-interrupting devices that will operate for a fault on Line 2. Therefore, the BES Transmission Line is defined between Sub 2 and Sub 4.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

*Line 5 is less than 100 kV; however, no exception has been obtained through the NERC Rules of Procedure Exception Process and therefore, the line is not BES.

Example 3: Aggregate Weight Value below 6,000 after Applying Exception to the GCTE

In example 3 below, BES Cyber System(s) are associated with a Control Center that monitors and controls nineteen BES Transmission Lines, of which 14 are to be excluded from the calculation using the GCTE exception. The entity should first calculate its aggregate weighted value, referencing the table located in Criterion 2.12. The entity is eligible to calculate a modified aggregate weighted value if the original aggregate weighted value is less than 12,000. In order to calculate the Control Center's modified aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12, and the exclusion language, and sum the weighted values for each BES Transmission Line that is not part of a single GCTE that was defined by the entity in accordance with the exclusion clause.



Note: Substation equipment (e.g., transformers) is not shown for simplicity.

Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 9,400, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity is eligible to calculate a modified aggregate weighted value that excludes a single group of contiguous transmission Elements (GCTE) in accordance with the exclusion clause.

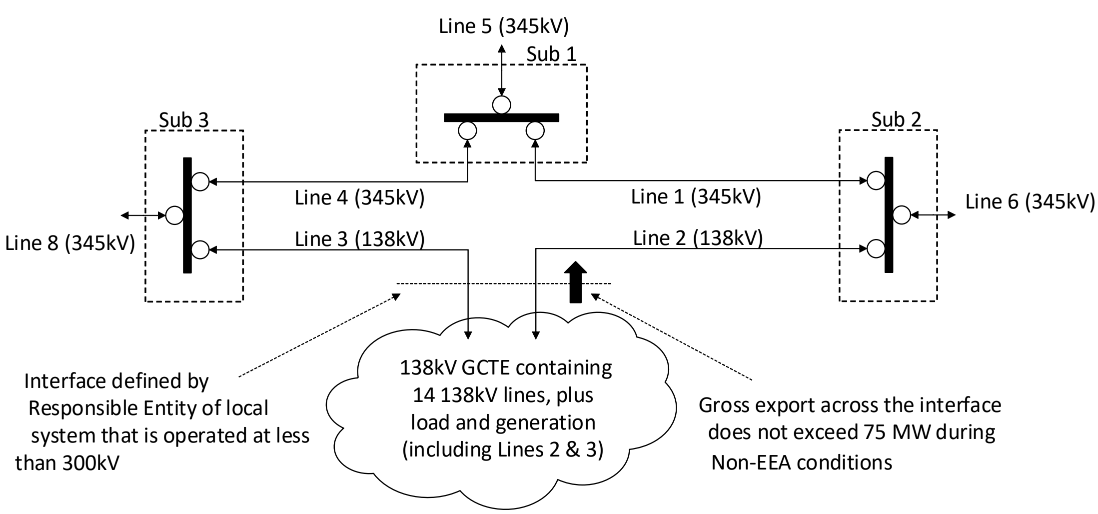
Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 2, Line 3, 12 additional lines	3500
200 kV to 299 kV	700	Line 6	700
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 8	5200
500 kV and above	0	None	0

The calculation of the modified aggregate weighted value is demonstrated below and equates to an aggregate weighted value of 5,900, which is below the minimum threshold for the medium impact rating required in Criterion 2.12. The BES Cyber System(s) associated with the Control Center in this example should be categorized as low impact BES Cyber System(s) pursuant to Criterion 3.1.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 6	700
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 8	5200
500 kV and above	0	None	0

*Lines 2 and 3 (along with the 12 additional lines located in the 138kV GCTE system) are excluded from the calculation because the Responsible Entity has defined an interface to a GCTE that is operated at less than 300kV, where the gross export across the interface does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions.

Example 4: Aggregate Weight Value above 6,000 after Applying Exception to the GCTE
In example 4 below, BES Cyber System(s) are associated with a Control Center that monitors and controls nineteen BES Transmission Lines, of which 14 are to be excluded from the calculation using the GCTE exception. The entity should first calculate its aggregate weighted value, referencing the table located in Criterion 2.12. The entity is eligible to calculate a modified aggregate weighted value if the original aggregate weighted value is less than 12,000. In order to calculate the Control Center's modified aggregate weighted value, the Responsible Entity should reference the table located in Criterion 2.12, and the exclusion language, and sum the weighted values for each BES Transmission Line that is not part of a single GCTE that was defined by the entity in accordance with the exclusion clause.



Note: Substation equipment (e.g., transformers) is not shown for simplicity.

Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 10,000, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. Given that the calculated aggregated weighted value is less than

12,000, the Responsible Entity is eligible to calculate a modified aggregate weighted value that excludes a single group of contiguous transmission Elements (GCTE) in accordance with the exclusion clause.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 2, Line 3, 12 additional lines	3500
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 6, Line 8	6500
500 kV and above	0	None	0

The calculation of the modified aggregate weighted value is demonstrated below and equates to an aggregate weighted value of 6,500, which is above the minimum threshold for the medium impact rating required in Criterion 2.12. In accordance with Criterion 2.12, the BES Cyber System(s) associated with the Control Center should be categorized as medium impact BES Cyber System(s).

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 6, Line 8	6500
500 kV and above	0	None	0

*Lines 2 and 3 (along with the 12 additional lines located in the 138kV GCTE system) are excluded from the calculation because the Responsible Entity has defined an interface to a GCTE that is operated at less than 300kV, where the gross export across the interface does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions.

Former Background Section from Reliability Standard CIP-002-5.1a

The Background section has been retired and removed from the standard and preserved by cutting and pasting as-is below.

Background

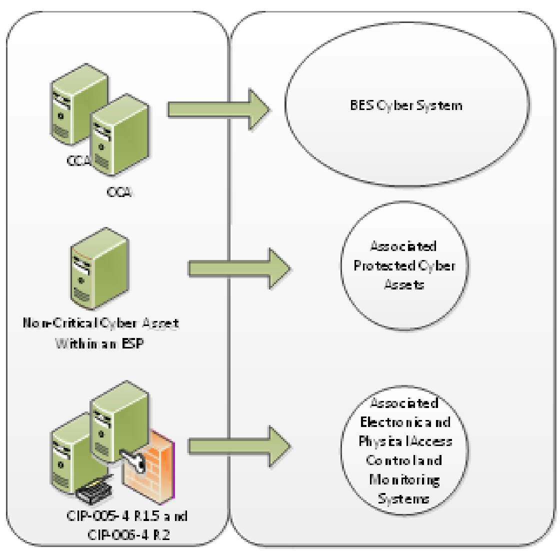
This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.

Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."

Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

BES Cyber Systems

One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.



In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.

Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.

It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations.

Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Reliable Operation of the BES

The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.

Real-time Operations

One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.

Categorization Criteria

The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4, and Criteria 2.1 to 2.11 default to be low impact.

This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.

Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems

BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or
(b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:

Electronic Access Control or Monitoring Systems (“ EACMS”)

Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.

Physical Access Control Systems (“ PACS”)

Examples include: authentication servers, card systems, and badge control systems.

Protected Cyber Assets (“ PCA”)

Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.

Technical Rationale for Reliability Standard CIP-002-5.1a

This section contains a "cut and paste" of the former Guidelines and Technical Basis (GTB) as-is of from the CIP-002-5.1a standard to preserve any historical references. No modifications have been made.

Guidelines and Technical Basis

Section 4 – Scope of Applicability of the CIP Cyber Security Standards

Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.

Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.

Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.

For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.

CIP-002 -5 .1a

CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."

The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-5.1a. The concept includes a number of named BES reliability operating services. These named services include:

- Dynamic Response to BES conditions
- Balancing Load and Generation
- Controlling Frequency (Real Power)
- Controlling Voltage (Reactive Power)
- Managing Constraints
- Monitor & Control
- Restoration of BES
- Situational Awareness
- Inter-Entity Real-Time Coordination and Communication

Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.

Entity Registration	RC	BA	TOP	TO	DP	GOP	GO
Dynamic Response		X	X	X	X	X	X
Balancing Load & Generation	X	X	X	X	X	X	X
Controlling Frequency		X				X	X
Controlling Voltage			X	X	X		X
Managing Constraints	X		X			X	
Monitoring and Control			X			X	
Restoration			X			X	
Situation Awareness	X	X	X			X	
Inter-Entity coordination	X	X	X	X		X	X

Dynamic Response

The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:

- Spinning reserves (contingency reserves)
    - Providing actual reserve generation when called upon (GO,GOP)
    - Monitoring that reserves are sufficient (BA)
- Governor Response
    - Control system used to actuate governor response (GO)
        - Protection Systems (transmission & generation)
    - Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)
    - Zone protection for breaker failure (DP, TO, TOP)
    - Breaker protection (DP, TO, TOP)
    - Current, frequency, speed, phase (TO,TOP, GO,GOP)
        - Special Protection Systems or Remedial Action Schemes
    - Sensors, relays, and breakers, possibly software (DP, TO, TOP)
        - Under and Over Frequency relay protection (includes automatic load shedding)
    - Sensors, relays & breakers (DP)
        - Under and Over Voltage relay protection (includes automatic load shedding)
    - Sensors, relays & breakers (DP)
        - Power System Stabilizers (GO)

Balancing Load and Generation

The Balancing Load and Generation Operations Service includes activities, actions, and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:

- Calculation of Area Control Error (ACE)
    - Field data sources (real time tie flows, frequency sources, time error, etc.) (TO, TOP)
    - Software used to perform calculation (BA)
- Demand Response
    - Ability to identify load change need (BA)
    - Ability to implement load changes (TOP,DP)

- Manually Initiated Load shedding
  - Ability to identify load change need (BA)
  - Ability to implement load changes (TOP, DP)
- Non-spinning reserve (contingency reserve)
  - Know generation status, capability, ramp rate, start time (GO, BA)
  - Start units and provide energy (GOP)

Controlling Frequency (Real Power)
The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:

- Generation Control (such as AGC)
  - ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)
  - Software to calculate unit adjustments (BA)
  - Transmit adjustments to individual units (GOP)
  - Unit controls implementing adjustments (GOP)
- Regulation (regulating reserves)
  - Frequency source, schedule (BA)
  - Governor control system (GO)

Controlling Voltage (Reactive Power)
The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:

- Automatic Voltage Regulation (AVR)
  - Sensors, stator control system, feedback (GO)
- Capacitive resources
  - Status, control (manual or auto), feedback (TOP, TO,DP)
- Inductive resources (transformer tap changer, or inductors)
  - Status, control (manual or auto), feedback (TOP,TO,DP)
- Static VAR Compensators (SVC)
  - Status, computations, control (manual or auto), feedback (TOP, TO,DP)

Managing Constraints

Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:

- Available Transfer Capability (ATC) (TOP)
- Interchange schedules (TOP, RC)
- Generation re-dispatch and unit commit (GOP)
- Identify and monitor SOL's & IROL's (TOP, RC)
- Identify and monitor Flow gates (TOP, RC)

Monitoring and Control

Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:

- All methods of operating breakers and switches
  - SCADA (TOP, GOP)
  - Substation automation (TOP)

Restoration of BES

The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance.

Aspects of the Restoration of BES function include, but are not limited to:

- Restoration including planned cranking path
  - Through black start units (TOP, GOP)
  - Through tie lines (TOP, GOP)
- Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)
- Coordination (TOP, TO, BA, RC, DP, GO, GOP)

Situational Awareness

The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:

- Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)
- Change management (TOP,GOP,RC,BA)
- Current Day and Next Day planning (TOP)
- Contingency Analysis (RC)
- Frequency monitoring (BA, RC)

Inter-Entity Coordination

The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:

- Scheduled interchange (BA,TOP,GOP,RC)
- Facility operational data and status (TO, TOP, GO, GOP, RC, BA)
- Operational directives (TOP, RC, BA)

Applicability to Distribution Providers

It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.

Requirement R1:

Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.

Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.

Attachment 1 Overall Application

In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.

- When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets.

For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.

- In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.
- It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.

High Impact Rating (H)

This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.

The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.

Additional thresholds as specified in the criteria apply for this category.

Medium Impact Rating (M)

Generation

The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.

- Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.

  In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.

  By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.

- The drafting team also used additional time and value parameters to ensure the bright- lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.

- In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.

If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.

The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.

- Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.

  IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.

- Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.

- Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.

- Criterion 2.13 categorizes as medium impact those BA Control Centers that “control” 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Transmission

The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.

- Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.
- Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.

  It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.
- Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:
  - Excluded radial facilities that would only provide support for single generation facilities.
  - Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.

  The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation.

The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.

Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:

- 230 kV –> 700 MVA
- 345 kV –> 1,300 MVA
- 500 kV –> 2,000 MVA
- 765 kV –> 3,000 MVA

In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:

- For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.
- Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.
- Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.

  Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.

  1. The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations.

This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.

2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000. The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.

- Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, Establish and Communicate System Operating Limits, R5.1.1 and R5.1.3.
- Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.
- Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.
- Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.
- Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system,

but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.

This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.

In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.

- Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.
- Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.

Low Impact Rating (L)

BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.

Restoration Facilities

- Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.

In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.

The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.

Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.

BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.

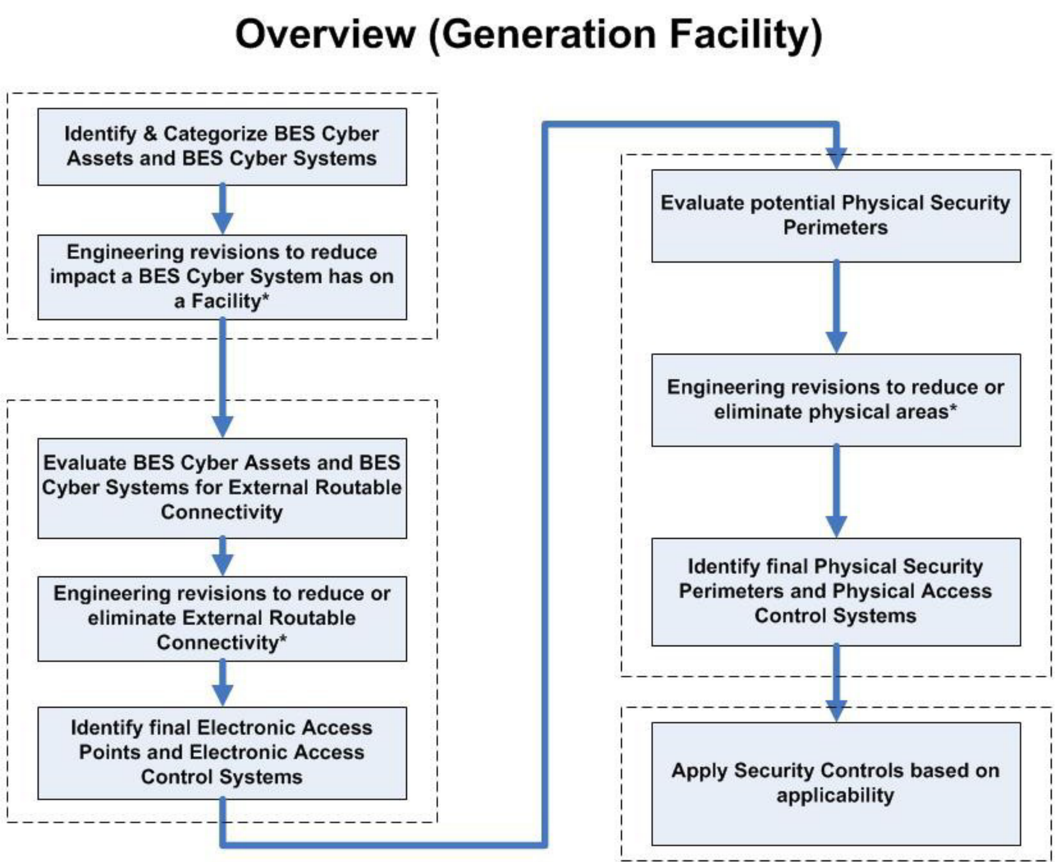
Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERCStandard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."

- BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.

Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.

Use Case: CIP Process Flow

The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.



* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

Rationale

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

Rationale for R1:
BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of “bright-line” criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.

Rationale for R2:
The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager’s approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.

Appendix 1

Requirement Number and Text of Requirement

CIP-002-5.1, Requirement R1

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:

i. Control Centers and backup Control Centers;

ii. Transmission stations and substations;

iii. Generation resources;

iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;

v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and

vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

Attachment 1, Criterion 2.1

2. Medium Impact Rating (M)

Each BES Cyber System, not included in Section 1 above, associated with any of the following:

2.1 Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

Questions

Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase “shared BES Cyber Systems.”

The Interpretation Drafting Team identified the following questions in the RFI:

1. Whether the phrase “shared BES Cyber Systems” means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?
3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

Responses

Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?

The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)

Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:

> The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.

Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?

The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.

The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:

> Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1: **Impact Rating of Generation Resource Shared BES Cyber Systems** for further information and examples.

Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?

The phrase applies to each discrete BES Cyber System.

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Standards Announcement

Project 2021-03 CIP-002

Formal Comment Period Open through May 16, 2024

Now Available

A formal comment period for **draft two of CIP-002-Y — Cyber Security - BES Cyber System Categorization**, is open through **8 p.m. Eastern, Thursday, May 16, 2024**.

The drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

There are currently two drafting teams working on modifications to CIP-002-5.1a. The Project 2021-03 standard drafting team is posting modifications as CIP-002-Y to differentiate its work from Project 2016-02 Modifications to CIP Standards (CIP-002-7).

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.

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

Next Steps

Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **May 7 – 16, 2024**.

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

For more information or assistance, contact 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 2021-03 CIP-002” in the Description Box.

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

Comment Report

Project Name:	2021-03 CIP-002 | Draft 2
Comment Period Start Date:	4/2/2024
Comment Period End Date:	5/16/2024
Associated Ballots:	2021-03 CIP-002 CIP-002-Y AB 2 ST 2021-03 CIP-002 Implementation Plan AB 2 OT

There were 67 sets of responses, including comments from approximately 166 different people from approximately 100 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Based on industry comments, the SDT has modified the Control Center definition. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

2. Language throughout Attachment 1 of CIP-002-Y that referred to the "functional obligations" of the different Registered Entities has been replaced with specific references to Control Centers that are either operated by or owned by the relevant Registered Entities. This change was incorporated given that the NERC Functional Model is no longer being actively maintained. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal. Does the change introduce reliability gaps to the Registered Entities? If it does, please provide your rationale.

3. The SDT intentionally constructed the exclusion clause within criteria 2.12 of Attachment 1 of CIP-002-Y to require an entity to measure gross export from their defined group of contiguous transmission Elements (GCTE). This accounts for both generation output and flow-through the GCTE. It ensures that an entity is unable to define a GCTE that contains significant generation that supports the BES or with significant flow-through that impacts the BES. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	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	1,3	MRO

						Company (MEC)		
					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
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	TVA RBB	Ian Grant	Tennessee Valley Authority	3	SERC
					David Plumb	Tennessee Valley Authority	1	SERC
					Armando Rodriguez	Tennessee Valley Authority	6	SERC
					Nehtisha Rollis	Tennessee Valley Authority	5	SERC
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

Con Ed - Consolidated Edison Co. of New York	Dermot Smyth	1	NPCC	Con Edison	Dermot Smyth	Con Edison Company of New York	1,3,5,6	NPCC
					Edward Bedder	Orange & Rockland		NPCC
Manitoba Hydro	Jay Sethi	1,3,5,6	MRO	Manitoba Hydro Group	Nazra Gladu	Manitoba Hydro	1	MRO
					Mike Smith	Manitoba Hydro	3	MRO
					Kristy-Lee Young	Manitoba Hydro	5	MRO
					Kelly Bertholet	Manitoba Hydro	6	MRO
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					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
Southern Company - Southern Company Services, Inc.	Jennifer Tidwell	1,3,5,6	SERC	Southern Company	Leslie Burke	Southern Company - Southern Company Generation	5	SERC
					Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC

					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
ACES Power Marketing	Jodirah Green	1	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Colette Caudill	East Kentucky Power Cooperative	1,3	SERC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF

					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Northern California Power Agency	Michael Whitney	3		NCPA	Scott Tomashefsky	Northern California Power Agency	4	WECC
					Marty Hostler	Northern California Power Agency	5,6	WECC
					Marty Hostler	Northern California Power Agency	5,6	WECC
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Micah Runner	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC

Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
David Burke	Orange and Rockland	3	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
David Kwan	Ontario Power Generation	4	NPCC
Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
Sean Cavote	PSEG	4	NPCC
Jason Chandler	Con Edison	5	NPCC
Tracy MacNicoll	Utility Services	5	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC
Vijay Puran	New York State Department of Public Service	6	NPCC
David Kiguel	Independent	7	NPCC
Joel Charlebois	AESI	7	NPCC
Joshua London	Eversource Energy	1	NPCC
Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC

					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Emma Halilovic	Hydro One Networks, Inc.	1,2	NPCC
					Chantal Mazza	Hydro Quebec	1,2	NPCC
					Nicolas Turcotte	Hydro-Quebec (HQ)	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
Portland General Electric Co.	Ryan Olson	5		PGE Group	Brooke Jockin	Portland General Electric Co.	1	WECC
					Stefanie Burke	Portland General Electric Co.	6	WECC
					Mayra Franco	Portland General Electric Co.	3	WECC
					Ryan Olson	Portland General Electric Co.	5	WECC
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
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Based on industry comments, the SDT has modified the Control Center definition. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports EEI's comment of bringing back the "associated data center" langauge.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	No
Document Name	
Comment	
Manitoba Hydro thanks the drafting team for a difficult task and agrees with their direction with the update. The use of one term "Control Center" instead of two is a good direction especially since the term "Data Center" is only used by the "Control Center" definition and not used elsewhere in the standards. Manitoba Hydro agrees with the use of the term "SCADA" in identifying #4 Transmission Owner Control Centers. Using an existing defined term helps with differentiation for different types of control that may exist. The definition, modifications to Attachment 1 and technical rational do not address the idea of "aggregate control" sufficiently. For example, if a room with operating personnel has two different independent UCMS computers, each controlling two different locations, there would be no additional cyber security risk compared to a local station UCMS and it is difficult to distinguish which are Control Center Cyber Assets vs. local station Cyber Assets. However, if a single Cyber Asset had control over multiple Facilities at multiple locations, then this "aggregate control" would be the Control Center Cyber Asset. Manitoba Hydro proposes the following definition change, re-ordering the definition of #4 to clarify that the SCADA system itself must have the capability	

to control multiple Transmission Facilities and two or more locations: 4) Transmission Owner personnel who use a Supervisory Control and Data Acquisition (SCADA) system that has the capability to control Transmission Facilities at two or more locations; or Manitoba Hydro also requests that the drafting team offer guidance in the technical rational for Facilities that span a large geographic area such as a Transmission line. A single Facility should be treated as a single location, even if it spans a large geographic area.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

We like the GOP Control Center definition. That same language needs to be included in IRC 2.11 “perform the reliability tasks of a GOP for generation Facilities that aggregate to or above a nRP threshold of 1500MW”. History has shown that auditors will only look at the IRC 2.11 criterion and not the standard applicability section. It should not be like this, but we entities have to deal with this problem later, if it not corrected now.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power is concerned about the proposed revisions to the Control Center definition. Specifically, the statement "and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time" could be interpreted to mean that any rooms with plant

control system equipment would be considered Control Centers, or that voice and data transport equipment would be classified as required for operating personnel to monitor and control the BES. Tacoma Power recommends the following edit to resolve this concern: “One or more facilities used by the operating personnel described below to monitor and control the BES in real-time.”

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	No
Document Name	
Comment	

TVA disagrees with the change from “hosting operating personnel” to “used by the operating personnel”. The proposed language is inappropriately over-broad and has the potential to errantly identify Transmission Facilities as Control Centers, a function they were never intended to execute.

Including the Transmission Owner as personnel that can perform operations would suggest identifying what some would identify as field personnel as Transmission Operators which are required to maintain certifications as operators and cross roles within an entity.

The capability to operate, monitor, or control elements located at separate low generation sites does not create a Control Center.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
see comments by NCPA Marty Hostler	
Likes 0	
Dislikes 0	

Response	
Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	No
Document Name	
Comment	
See comments by NCPA Marty Hostler	
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 thanks the drafting team for a difficult task and agrees with their direction with the update. The use of one term “Control Center” instead of two is a positive direction especially since the term “Data Center” is only used by the “Control Center” definition and not used elsewhere in the standards.

The MRO NSRF agrees with the use of the term “SCADA” in identifying #4 Transmission Owner Control Centers. Using an existing defined term helps with differentiation for different types of control that may exist.

The definition and technical rational do not address the idea of “aggregate control”. For example, if a room with operating personnel has two different independent UCMS computers, each controlling two different locations, there would be no additional cyber security risk and it is difficult to distinguish which are Control Center Cyber Assets vs. local station Cyber Assets. If one Cyber Asset had control over multiple locations, then this aggregate control would be the Control Center Cyber Asset.

The MRO NSRF proposes the following definition change, re-ordering the words in the definition to clarify that the SCADA system itself must have the

capability to control multiple Transmission Facilities and two or more locations: 4) Transmission Owner personnel who use a Supervisory Control and Data Acquisition (SCADA) system that has the capability to control Transmission Facilities at two or more locations; or	
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	

1) The Control Center definition, it starts out referring to “one or more facilities” however it then excludes assets (cyber assets) such as RTU and data aggregation asset which cause confusion with how to evaluate if a location meets the new Control center definition. TFIST proposes that the wording reflect the Technical rational more closely and any exception be put in an exception section of the definition. Suggest using: Any facilities that contain Cyber Assets required for personnel to monitor and control BES Facilities at two or more locations in Real-time, whether they are co-located or separately located from the physical location of the personnel, excluding field facilities.

2) The use of both “operating personnel” and “personnel” in part 1-5 can be misinterpreted, suggest just using personnel.

3) Clarify whether the use of the NERC defined term "Real-time" and the non-NERC defined term "real-time" is intended. If it is intended, we recommend, for the sake of consistency and understanding, to standardize on one or the other.

4) The proposed changes Control Center definition change is too specific to the architecture of the building and there are various scenarios that could be subject to the definition that should be clarified prior to implementation.

For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

i. If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers but no one is assigned to that desk, is the engineering office a Control Center? or

ii. If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or

iii. If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or

iv. If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center?

If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field

personnel, is this room a Control Center?	
Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy supports EEI comments which state:

EEI appreciates the drafting team's efforts to modify the Control Center definition using feedback submitted during the last ballot but is concerned about unintended impacts that could occur as a result of the proposed changes.

EEI does not agree with revising the Control Center definition to reference "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time" and prefers reverting to the original "associated data centers" language as follows:

"One or more facilities used by the operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time, and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time including their associated data center(s)."

The "any facilities" language could be broadly interpreted to encompass facilities that were not intended by the drafting team, and clarity regarding the term 'data center' could be achieved via other means such as technical rationale, implementation guidance, or other supporting materials.

EEI also seeks clarity on the reference to "field assets" in the draft Control Center definition. The definition clearly excludes remote terminal units and data aggregators from its scope. The CIP Standards include specific language that excludes Cyber Assets associated with communication networks and data communication links between Electronic Security Perimeters, which places boundaries on the field assets that could be pulled into scope, but that does not apply throughout the rest of the NERC Reliability Standards. Given the prolific use of the Control Center definition throughout the NERC Reliability Standards, we ask the drafting team to consider further clarifying what is intended by "field assets."

EEI is concerned with use of "Transmission Owner personnel who have the capability to" because it could unintentionally expand the scope of the Control Center definition based on who is capable of controlling instead of the systems at facilities with the capability. EEI suggests the following revision:

"4) Transmission Owner personnel who facilities that have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA); or"

Additionally, the revisions to the Control Center definition, combined with changes to the Attachment 1, Section 2 header to include "used by and located at", and the criteria leads to the determination of an impact rating for a BCS based on the total MW controlled by the facility that it is located in instead of based on what it can impact. While this may not be as impactful for traditional BA/RC/TOP Control Centers with single large BCS, it is impactful for GOPs who may have completely separate systems, networks, and personnel dispatching multiple distinct generation fleets from a single facility. Even if the separate systems are low impact, if they are located at the same facility, they could all

be considered medium impact under this construct without any meaningful change to the risk to the Bulk Electric System.

EEI is concerned about the following scenarios related to the proposed Control Center definition and requests the development of Implementation Guidance, and the inclusion of these scenarios in the Technical Rationale to address the concerns:

The impact of the revised Control Center definition for a DC line where, today, there is a transmission substation at each end of the line, not a Control Center. Section 4 of the definition potentially brings into scope the ICS DC line system with an HMI as a Control Center. As written, it is not clear if a person operating two ends of the DC line at one substation would be considered a Control Center. EEI seeks clarity for this scenario and asks the drafting team to consider an exclusion for this scenario.

The impacts to renewables and GOPs are unclear. While we appreciate the inclusion of the “perform the reliability tasks” language, there are scenarios that have not been clarified such as the use of vendor provided performance management systems where the vendor may have ethe ability to change settings remotely.

It is also not clear if a transmission or distribution maintenance facility with access to modify relay settings without the real-time function at multiple sites at medium, low, or non-CIP impact ratings would be considered a Control Center under the new proposed Control Center definition.

Lastly, EEI notes that revisions to the Control Center definition could have an impact on other recent industry approved Standards including those modified through Project 2016-02 Virtualization and Project 2023-03 Internal Network Security Monitoring. These revisions should be compared against those projects to identify and mitigate unintended consequences, and to deconflict implementation dates.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	

Comment

In the Control Center definition item #4 specifically calls out the capability to control Transmission Facilities via SCADA systems. If the intent is to exclude field switching personnel and maintenance staff or personnel who may control per instructions as suggested in the Technical Rationale on Page 2, we suggest the following wording for item # 4 for better clarity.

4) Transmission Owner personnel who use Supervisory Control and Data Acquisition (SCADA) to control Transmission Facilities at two or more locations in real-time. TO personnel excludes field switching and support personnel.

In items #4 and #5 of the Control Center definition “the use of term real-time” was removed from previous Draft 1. The SDT team's response to Draft1 and the technical rational (refer to page 2) still use the term “in real-time” for the Transmission Owner and Generation Operator. BC Hydro suggests

using the non-capitalized real-time term. PER-005-2 Applicability 4.1.5.1 excludes Generator Operator personnel that are plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay instructions without making any modifications. BC Hydro suggests that this exclusion be reflected in the Control Center definition as follows. 5) Generator Operator personnel who perform the reliability tasks of a Generator Operator for the generation Facilities at two or more locations in real-time. These personnel do not include plant operators located at a generator plant site or personnel at a centrally located dispatch center who relay dispatch instructions without making any modifications. BC Hydro recommends that these clarifications be addressed within the language of the CIP-002-Y Standard.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	2021-03_Unofficial_Comment_Form_- EEI Near Final Comments Clean.docx
Comment	
See attached comments from EEI, which we endorse for all 4 questions.	
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 appreciates the drafting team's efforts to modify the Control Center definition using feedback submitted during the last ballot but is concerned about unintended impacts that could occur as a result of the proposed changes. EEI does not agree with revising the Control Center definition to reference "any facilities that contain the Cyber Assets required for operating personnel	

to monitor and control the BES in real-time" and prefers reverting to the original "associated data centers" language as follows:

"One or more facilities used by the operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time, **including their associated data center(s)**."

The "any facilities" language could be broadly interpreted to encompass facilities that were not intended by the drafting team, and clarity regarding the term 'data center' could be achieved via other means such as technical rationale, implementation guidance, or other supporting materials.

EEI also seeks clarity on the reference to "field assets" in the draft Control Center definition. The definition clearly excludes remote terminal units and data aggregators from its scope. The CIP Standards include specific language that excludes Cyber Assets associated with communication networks and data communication links between Electronic Security Perimeters, which places boundaries on the field assets that could be pulled into scope, but that does not apply throughout the rest of the NERC Reliability Standards. Given the prolific use of the Control Center definition throughout the NERC Reliability Standards, we ask the drafting team to consider further clarifying what is intended by "field assets."

EEI is concerned with use of "Transmission Owner personnel who have the capability to" because it could unintentionally expand the scope of the Control Center definition based on who is capable of controlling instead of the systems at facilities with the capability. EEI suggests the following revision:

"4) Transmission Owner (*remove: personnel who)* **facilities that** have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA); or"

Additionally, the revisions to the Control Center definition, combined with changes to the Attachment 1, Section 2 header to include "used by and located at", and the criteria leads to the determination of an impact rating for a BCS based on the total MW controlled by the facility that it is located in instead of based on what it can impact. While this may not be as impactful for traditional BA/RC/TOP Control Centers with single large BCS, it is impactful for GOPs who may have completely separate systems, networks, and personnel dispatching multiple distinct generation fleets from a single facility. Even if the separate systems are low impact, if they are located at the same facility, they could all be considered medium impact under this construct without any meaningful change to the risk to the Bulk Electric System.

EEI is concerned about the following scenarios related to the proposed Control Center definition and requests the development of Implementation Guidance, and the inclusion of these scenarios in the Technical Rationale to address the concerns. :

The impact of the revised Control Center definition for a DC line where, today, there is a transmission substation at each end of the line, not a Control Center. Section 4 of the definition potentially brings into scope the ICS DC line system with an HMI as a Control Center. As written, it is not clear if a person operating two ends of the DC line at one substation would be considered a Control Center. EEI seeks clarity for this scenario and asks the drafting team to consider an exclusion for this scenario.

The impacts to renewables and GOPs are unclear. While we appreciate the inclusion of the "perform the reliability tasks" language, there are scenarios that have not been clarified such as the use of vendor provided performance management systems where the vendor may have the ability to change settings remotely.

It is also not clear if a transmission or distribution maintenance facility with access to modify relay settings without the real-time function at multiple sites at medium, low, or non-CIP impact ratings would be considered a Control Center under the new proposed Control Center definition.

Lastly, EEI notes that revisions to the Control Center definition could have an impact on other recent industry approved Standards including those modified through Project 2016-02 Virtualization and Project 2023-03 Internal Network Security Monitoring. These revisions should be compared against those projects to identify and mitigate unintended consequences, and to deconflict implementation dates.

Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	No
Document Name	
Comment	

Disagree with the proposed language “and any facilities that contain Cyber Assets required for operating personnel to monitor and control the BES in real-time.” This language is not clear in describing an associated data center. Is the DT excluding all Cyber Assets at the asset being controlled? Suggest further clarification in the proposed language. Request clarification on field assets, this is an undefined term and is unclear. Suggest utilizing the term “field Cyber Assets” as it provides more clarification.

Request clarification on the difference between lower case “real-time” and the “real time” in the bros of the proposed technical rationale.

The proposed language “one or more facilities used by operating personnel” in the beginning of the definition causes some confusion when determining where the Control Center is located. Suggest clarifying this phrase to limit the location to a single site or building. Additionally, USV suggest maintaining consistency with the term “facilities”, what does the DT intend to encompass with the term “facilities”?

USV also recommends using the singular term “Cyber Asset” in the proposed definition.

There are various scenarios that could be subject to the definition that should be clarified prior to implementation.

For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

1. If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers, but no one is assigned to that desk, is the engineering office a Control Center? or

2. If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or

3. If an engineer remotes into the SCADA system from a remote location (home office, Starbucks) is this room now a Control Center?

4. If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a Control Center?

5. If a manufacturer like GE can access multiple generation sites for maintenance purposes is that facility a Control Center?

Likes 0	
Dislikes 0	

Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	No
Document Name	
Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	

Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this question.	
Likes 0	
Dislikes 0	

Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric LLC, (CEHE) believes the proposed changes to the Control Center definition may have unintended impacts. CEHE does not agree with revising the definition to include “any facilities that contain the Cyber Assets required for operating personnel to monitor and	

control the Bulk Electric System (BES) in real time" and suggests the original language, which includes "associated data centers."

CEHE, would also like clarity on the reference to "field assets" in the proposed Control Center definition. The CIP Standards already exclude Cyber Assets associated with communication networks and data communication links between Electronic Security Perimeters, which limits the scope of field assets. The use of "who have the capability to" for Transmission Owner personnel could expand the scope and increase the evidentiary burden to prove that TO personnel do not have the capability, which provides little value to reliability. CEHE, agrees with EEI, and expresses worry that the definition could unintentionally bring ICS systems into scope. The revisions should be compared against other projects such as Project 2016-02 to identify and mitigate unintended consequences and deconflict implementation dates.

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

NEE supports EEI's comments: EEI appreciates the drafting team's efforts to modify the Control Center definition using feedback submitted during the last ballot but is concerned about unintended impacts that could occur as a result of the proposed changes.

EEI does not agree with revising the Control Center definition to reference "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time" and prefers reverting to the original "associated data centers" language as follows:

"One or more facilities used by the operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time, and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time **including their associated data center(s)**."

The "any facilities" language could be broadly interpreted to encompass facilities that were not intended by the drafting team, and clarity regarding the term 'data center' could be achieved via other means such as technical rationale, implementation guidance, or other supporting materials.

EEI also seeks clarity on the reference to "field assets" in the draft Control Center definition. The definition clearly excludes remote terminal units and data aggregators from its scope. The CIP Standards include specific language that excludes Cyber Assets associated with communication networks and data communication links between Electronic Security Perimeters, which places boundaries on the field assets that could be pulled into scope, but that does not apply throughout the rest of the NERC Reliability Standards. Given the prolific use of the Control Center definition throughout the NERC Reliability Standards, we ask the drafting team to consider further clarifying what is intended by "field assets."

EEI is concerned with use of "Transmission Owner personnel who have the capability to" because it could unintentionally expand the scope of the Control Center definition based on who is capable of controlling instead of the systems at facilities with the capability. EEI suggests the following revision:

"4) Transmission Owner personnel who **facilities that** have the capability to control Transmission Facilities at two or more locations using Supervisory

Control and Data Acquisition (SCADA); or"

Additionally, the revisions to the Control Center definition, combined with changes to the Attachment 1, Section 2 header to include "used by and located at", and the criteria leads to the determination of an impact rating for a BCS based on the total MW controlled by the facility that it is located in instead of based on what it can impact. While this may not be as impactful for traditional BA/RC/TOP Control Centers with single large BCS, it is impactful for GOPs who may have completely separate systems, networks, and personnel dispatching multiple distinct generation fleets from a single facility. Even if the separate systems are low impact, if they are located at the same facility, they could all be considered medium impact under this construct without any meaningful change to the risk to the Bulk Electric System.

EEI is concerned about the following scenarios related to the proposed Control Center definition and requests the development of Implementation Guidance, and the inclusion of these scenarios in the Technical Rationale to address the concerns. :

The impact of the revised Control Center definition for a DC line where, today, there is a transmission substation at each end of the line, not a Control Center. Section 4 of the definition potentially brings into scope the ICS DC line system with an HMI as a Control Center. As written, it is not clear if a person operating two ends of the DC line at one substation would be considered a Control Center. EEI seeks clarity for this scenario and asks the drafting team to consider an exclusion for this scenario.

The impacts to renewables and GOPs are unclear. While we appreciate the inclusion of the "perform the reliability tasks" language, there are scenarios that have not been clarified such as the use of vendor provided performance management systems where the vendor may have the ability to change settings remotely.

It is also not clear if a transmission or distribution maintenance facility with access to modify relay settings without the real-time function at multiple sites at medium, low, or non-CIP impact ratings would be considered a Control Center under the new proposed Control Center definition.

Lastly, EEI notes that revisions to the Control Center definition could have an impact on other recent industry approved Standards including those modified through Project 2016-02 Virtualization and Project 2023-03 Internal Network Security Monitoring. These revisions should be compared against those projects to identify and mitigate unintended consequences, and to deconflict implementation dates.

Likes 0	
Dislikes 0	

Response

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3

Answer	No
Document Name	

Comment

PNM and TNMP agree with EEI comments. We offer these additional comments regarding identification of associated data centers.

The revised Control Center definitions includes "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the

BES in real-time." So this is ANY facility that contain Cyber Assets require for monitor and control of the BES? This would mean any telecommunication facility that monitor and control functions traverse through would be in-scope. This is one of the reasons for using the associated data center language to help avoid scoping in telecommunication facilities that are not under the jurisdiction of FERC.

Additionally, the definition states that a Control Center is "…any facilities that contain Cyber Assets…" or as EEI put is Cyber Systems. First Cyber Systems is not a NERC defined term, so that won't work. While the DT proposed definition states Cyber Asset it could be misread BES Cyber Assets. The issue is that with CIP-002 you need to identify the BES Cyber Assets or BES Cyber Systems associated with the Control Center. So is an entity coming into CIP for the first time supposed to determine its Control Center footprint by first identifying Cyber Assets used to monitor and control the BES in real-time only excluding field assets that are remote terminal units and data aggregators. Once that is done then you find the BES Cyber Systems at the Control Center. You started with Cyber Assets used to monitor and control the BES regardless of location and only excluded field assets. You are using Cyber Assets to define Control Centers which will lead to identification of BES Cyber Systems associated with Control Centers. It seems like a Chicken and the Egg paradox.

Based on the proposed definition, the Control Center could be any number of locations containing Cyber Assets used to monitor and control the BES such as all locations with system protection relays that are not excluded. Or is the definition saying any field device is excluded. The previous definition had supposed confusion over the term data center. Are the excluding term field devices truly well defined? Field devices cannot be those devices not in a Control Center because the term is being used to determine the scope of the Control Center and thus another Chicken and Egg paradox. In addition, does field devices include any Cyber Assets used by third party telecommunication providers which are required to monitor and control the BES in real-time? If so, how does the DT plan to scope out telecommunication providers that are not within FERC jurisdiction. Or are Responsible Entities now responsible for putting in contracts with telecommunication providers there need to comply with NERC CIP?

We cannot look at the definition from the point of view of established CIP programs but from a new entity starting anew. The definition change doesn't grandfather in existing systems so we would all need to start anew again. Either revert to the original language using associated data centers or define field assets further.

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Comments from EEI.	
Likes 0	
Dislikes 0	
Response	

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
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	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
1) The Control Center definition, it starts out referring to “one or more facilities” however it then excludes assets (cyber assets) such as RTU and data aggregation asset which cause confusion with how to evaluate if a location meets the new Control center definition. TFIST proposes that the wording reflect the Technical rational more closely and any exception be put in an exception section of the definition. Suggest using: Any facilities that contain	

Cyber Assets required for personnel to monitor and control BES Facilities at two or more locations in Real-time, whether they are co-located or separately located from the physical location of the personnel, excluding field facilities. 2) The use of both “operating personnel” and “personnel” in part 1-5 can be misinterpreted, suggest just using personnel. 3) Clarify whether the use of the NERC defined term "Real-time" and the non-NERC defined term "real-time" is intended. If it is intended, we recommend, for the sake of consistency and understanding, to standardize on one or the other. 4) The proposed changes Control Center definition change is too specific to the architecture of the building and there are various scenarios that could be subject to the definition that should be clarified prior to implementation. For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system: i. If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers but no one is assigned to that desk, is the engineering office a Control Center? or ii. If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or iii. If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or iv. If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center? v. If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a Control Center?	
Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	Comment Form--2021-03_Unofficial_Comment_Form--Submitted 5-15-24.pdf
Comment	
NB Power supports NPCC comments, see attached.	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment
EEI appreciates the drafting team's efforts to modify the Control Center definition using feedback submitted during the last ballot but is concerned about unintended impacts that could occur as a result of the proposed changes. EEI does not agree with revising the Control Center definition to reference "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time" and prefers reverting to the original "associated data centers" language as follows: "One or more facilities used by the operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time, **including their associated data center(s)**." The "any facilities" language could be broadly interpreted to encompass facilities that were not intended by the drafting team, and clarity regarding the term 'data center' could be achieved via other means such as technical rationale, implementation guidance, or other supporting materials. EEI also seeks clarity on the reference to "field assets" in the draft Control Center definition. The definition clearly excludes remote terminal units and data aggregators from its scope. The CIP Standards include specific language that excludes Cyber Assets associated with communication networks and data communication links between Electronic Security Perimeters, which places boundaries on the field assets that could be pulled into scope, but that does not apply throughout the rest of the NERC Reliability Standards. Given the prolific use of the Control Center definition throughout the NERC Reliability Standards, we ask the drafting team to consider further clarifying what is intended by "field assets." EEI is concerned with use of "Transmission Owner personnel who have the capability to" because it could unintentionally expand the scope of the Control Center definition based on who is capable of controlling instead of the systems at facilities with the capability. EEI suggests the following revision: "4) Transmission Owner **facilities that** have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA); or" Additionally, the revisions to the Control Center definition, combined with changes to the Attachment 1, Section 2 header to include "used by and located at", and the criteria leads to the determination of an impact rating for a BCS based on the total MW controlled by the facility that it is located in instead of based on what it can impact. While this may not be as impactful for traditional BA/RC/TOP Control Centers with single large BCS, it is impactful for GOPs who may have completely separate systems, networks, and personnel dispatching multiple distinct generation fleets from a single facility. Even if the separate systems are low impact, if they are located at the same facility, they could all be considered medium impact under this construct without any meaningful change to the risk to the Bulk Electric System. EEI is concerned about the following scenarios related to the proposed Control Center definition and requests the development of Implementation Guidance, and the inclusion of these scenarios in the Technical Rationale to address the concerns. The impact of the revised Control Center definition for a DC line where, today, there is a transmission substation at each end of the line, not a Control Center. Section 4 of the definition potentially brings into scope the ICS DC line system with an HMI as a Control Center. As written, it is not clear if a person operating two ends of the DC line at one substation would be considered a Control Center. EEI seeks clarity for this scenario and asks the drafting team to consider an exclusion for this scenario. The impacts to renewables and GOPs are unclear. While we appreciate the inclusion of the "perform the reliability tasks" language, there are scenarios that have not been clarified such as the use of vendor provided performance management systems where the vendor may have ethe ability to change settings remotely. It is also not clear if a transmission or distribution maintenance facility with access to modify relay settings without the real-time function at multiple sites

at medium, low, or non-CIP impact ratings would be considered a Control Center under the new proposed Control Center definition.

Lastly, EEI notes that revisions to the Control Center definition could have an impact on other recent industry approved Standards including those modified through Project 2016-02 Virtualization and Project 2023-03 Internal Network Security Monitoring. These revisions should be compared against those projects to identify and mitigate unintended consequences, and to deconflict implementation dates.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy supports EEI comments.

Likes 0	
Dislikes 0	

Response

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

SERC appreciates the hard work done the SDT has done under time pressure to respond to comments and turn the drafts around. Here are specific comments we have regarding the definition:

Item 1: With the move away from 'hosting operating personnel',explain if facilities used temporarily/in a transient manner by operating personnel would be treated or not treated as Control Centers. This could include situations such as individual operators working from home during a quarantine or when operating personnel are in transition between the normal primary and backup facilities and as described in EOP-008-2 R1.6.

Item 2: The current 'associated data centers' portion of the existing definition covers situations where EMS Cyber Assets which perform automated operations on the BES without operator input in real-time – such as Automated Switching Systems used for coordinated switching/sectionalizing in response to detected BES conditions or faults. The phrasing '…and required for operating personnel to monitor and control the BES in real-time..'

seems to require a human-in-the-loop as a qualifier. Would that be correct, to exclude automated actions taken by the EMS within the 15 minute real-time window?

Item 3: The statement *"Field assets such as remote terminal units and data aggregators are excluded from the scope of the Control Center definition"* does not appear in the results of the field trial, but instead seems to come from the interpretation request. The technical rational further states *"RTUs and data aggregation assets would be evaluated for Cyber Security requirements based on their location and the data that they are gathering."* This location-based identification doesn't typically happen in CIP Version 5 since the phasor measurement units, data aggregation assets, and metering data are considered non-essential to the reliable operation of the individual local TO Transmission Facility itself(substations) where they are geographically located and connected, but instead the data they contain are essential to the reliable operation via wide-area view and Real Time Monitoring/Real Time Assessments of a distant RC/BA/TOP's Control Center. This change, as well as the corresponding changes in Attachment 1 to add the 'used by and located at' language, may introduce a reliability gap if these Cyber Assets are now globally excluded by both the Control Center definition and then later at the Transmission Facility. Suggest removal of this phrasing and the additional 'used by and located at' Attachment language.

Item 4: The addition of the PER-005 sourced "BES company-specific" language for the RC, BA, and TOP are a good connecting point between CIP and O&P standards. However, where multiple TOPs divide the PER-005 reliability-related tasks between one who has authority/administrative control and one who has the technical ability to open breakers, are both types of TOPs included?

Item 5: In the TO section "4)" the phrase, "…using SCADA" would seem to exclude control methods and Cyber assets which use non 'SCADA' protocols to remotely effect control, such as RDP, HTTP, SSH, or SEL Fast Message directed at an HMI or other Cyber Asset located within the Transmission substation. Suggest instead this item be simplified to '…capability to control Transmission Facilities at two or more locations' since the presence of Cyber Asset or any/all types of protocols to operate/control will be handled within CIP-002 and the remainder of the CIP standards. Otherwise the term 'SCADA' would appear to be unclear or possibly exclusive of other methods used in today's BES to remotely control.

Item 6: In the GOP section "5)" the changed language states "Generator Operator personnel who perform the reliability tasks of a Generator Operator…" Does this limit applicability only to personnel employed by the Generator Operator company, or would it also include contractor personnel and contracted third-party entities/service providers that perform some portion of the reliability tasks of a Generator Operator? It is not uncommon, especially in the IBR sphere, for these tasks to be split and subdivided among multiple entities 'as a service', located in multiple different geographies. Suggest a return the 'functional obligations' language for the non-TO entities mentioned here, or otherwise clarify that GOP personnel are not limited solely to the GOP company if functions are distributed.

Likes 0	
Dislikes 0	

Response

Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker

Answer	No
Document Name	

Comment

Cleco agrees with EEI comments.

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) for question #1.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Avista supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy does not agree with the proposed modifications to the Control Center definition and continues to advocate for preservation of the original format of the definition. As in previous comments, we do not believe there to be widespread confusion concerning the definition but do understand that the drafting team is trying to address a specific gap where a TO may have the capability to control but not have a Control Center according to the current definition. If the drafting team determines that there is broad stakeholder support to continue modification of the Control Center definition, here is the language that we recommend: One or more facilities hosting operating personnel that can monitor and control the Bulk Electric System (BES) in Real-time to perform the reliability tasks, including their associated data centers, of a: 1) Reliability Coordinator, 2) Balancing Authority, 3) Transmission Operator for Transmission Facilities at two or more locations 4) Transmission Owner for Transmission Facilities at two or more locations, or 5) Generator Operator for generation Facilities at two or more locations We also support EEI and NAGF comments.

Likes 0	
Dislikes 0	
Response	
Jennifer Tidwell - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company is in agreement with EEI's comments.	
Likes 0	
Dislikes 0	

Response	
Beth Smail - AEP - 1,3,5,6 - MRO,Texas RE,RF	
Answer	No
Document Name	
Comment	
AEP agrees with some of EEI's concerns and recommend refinements to the Control Center definition.	
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 the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS agrees with EEI's comments regarding the need for clarity regarding the reference to "field assets" in the draft Control Center definition. Field asset which may be excluded through exemptions within the CIP standards may not be properly excluded in the rest of the NERC Reliability standards. AZPS also agrees with EEI's concern regarding the use of "Transmission Owner personnel who have the capability to". The focus should remain on	

facility capability rather than “personnel”. AZPS supports the EEI proposed revision “4) Transmission Owner (Remove*personnel who*) **facilities that** have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA); or”	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 3,4	
Answer	No
Document Name	
Comment	

While GSOC can understand the reasoning to expand the definition to include facilities containing Cyber Assets that can be used by TO personnel via SCADA to monitor and control transmission Facilities, GSOC recommends maintaining the word “hosting” for clarity and to the benefit of the existing operating personnel types; as removing the term could introduce ambiguity and unintentionally expand the facility to include an entire building or campus containing a control center(s) that is also used by operating personnel.

Additionally, since the term Facility already includes BES transmission and generation, and Real-time is already captured in the appropriate operating personnel descriptors, GSOC believes the definition can be refined further to eliminate redundant phrases and uncomplicate the definition via the following alternative:

One or more facilities hosting and/or used by the operating personnel described below to monitor and control Facilities at two or more locations in real-time, including any facilities that contain Cyber Assets required to monitor and control the Bulk Electric System (BES). Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition.

1. Reliability Coordinator personnel who perform the BES company-specific Real-time reliability related tasks of a Reliability Coordinator;
2. Balancing Authority personnel who perform the BES company-specific Real-time reliability-related tasks of a Balancing Authority;
3. Transmission Operator personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator;
4. Transmission Owner personnel who have the capability to control Transmission Facilities using Supervisory Control and Data Acquisition (SCADA); or
5. Generator Operator personnel who perform the reliability tasks of a Generator Operator.

Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	

Answer	No
Document Name	
Comment	
Exelon is aligning with the EEI in response to this question.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon is aligning with the EEI in response to this question.	
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 recommends that data centers be included in the Control Center definition.	
Likes 0	
Dislikes 0	
Response	

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	No
Document Name	
Comment	

NST disagrees with the SDT's decision to replace "One or more facilities hosting,..." with "One or more facilities used by..." We base this opinion on the fact that during the SDT's April 26 webinar, several participants asked, paraphrasing, if the proposed definition might compel identifying remote operators' home offices as Control Centers. We agree that "facilities used by" implies the physical presence of operations personnel, but we also believe that "facilities hosting" makes this inference clearer.

NST agrees with changing "associated data centers" to "facilities that contain the Cyber Assets required,..." but note the proposed changes do not address an issue that has come to the fore in the context of CIP-012: Do the respective physical locations of facilities hosting operators and facilities containing Cyber Assets needed by those operators play a role in determining the number of discrete Control Centers a Registered Entity should identify?

NST considers the proposed exception language, "Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition," to be unnecessary and a potentially bad precedent. In our opinion, the qualifying phrase, "used by and located at" in Attachment 1 adequately removes Cyber Assets at field assets such as substations and generation facilities from consideration as Control Center BES Cyber Systems.

NST believes the SDT should explain the use of the phrase, "company-specific" in the proposed definition's list of operating personnel.

Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	No
Document Name	
Comment	

We support EEI's comments.

Likes 0	
Dislikes 0	

Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5, Group Name PGE Group	
Answer	No
Document Name	
Comment	
PGE is in alignement with comments provided by EEI.	
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	

Although SMUD agrees with the proposed changes to the Control Center definition, the Standard Drafting Team should consider the following minor revision to improve the clarity of the definition. We believe this change is non-substantive and could be made in the final ballot. Control Center - One or more facilities used by the operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time**, and [delete "and"] which includes [add ", which includes"]** any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time. Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition. 1) Reliability Coordinator personnel who perform the BES company-specific Real-time reliability related tasks of a Reliability Coordinator; 2) Balancing Authority personnel who perform the BES company-specific Real-time reliabilityrelated tasks of a Balancing Authority; 3) Transmission Operator personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations; 4) Transmission Owner personnel who have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA); or 5) Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.	
Likes 0	
Dislikes 0	
Response	
Marie Potter - Marie Potter On Behalf of: Alison MacKellar, Constellation, 5, 6; Kimberly Turco, Constellation, 5, 6; - Marie Potter	
Answer	Yes
Document Name	
Comment	
Constellation agrees with expanding "associated data centers" to "facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in Real-time".	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
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	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 1,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE noticed the proposed definition includes an exclusion for "field assets", which is not a defined term. The definition provides two examples of field assets: remote terminal units and data aggregators. Texas RE notes that remote terminal units and data aggregators may also be located at Control Centers and included within one or more BES Cyber Systems.	

Texas RE recommends modifying the definition to state that Cyber Assets that are not located at the Control Center and are only capable of operating Facilities at one location are excluded from the Control Center definition. Texas RE recommends the following verbiage (addition in bold):

Field assets, such as terminal units and data aggregators **located at locations remote to the facilities used to monitor and control the Bulk Electric System** are excluded from the scope of the Control Center definition.

Likes 0	
Dislikes 0	

Response

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison

Answer	
Document Name	

Comment

Supporting EEI comments.

Likes 0	
Dislikes 0	

Response

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	
Document Name	

Comment

While we can understand the reasoning to expand the definition to include facilities containing Cyber Assets that can be used by TO personnel via SCADA to monitor and control transmission Facilities, we recommend maintaining the word “hosting” for clarity and to the benefit of the existing operating personnel types; as removing the term could introduce ambiguity and unintentionally expand the facility to include an entire building or campus containing a control center(s) that is also used by operating personnel.

Additionally, since the term Facility already includes BES transmission and generation, and Real-time is already captured in the appropriate operating personnel descriptors, we believe the definition can be refined further to eliminate redundant phrases and uncomplicate the definition via the following alternative:

One or more facilities hosting and/or used by the operating personnel described below to monitor and control Facilities at two or more locations in real-time, including any facilities that contain Cyber Assets required to monitor and control the Bulk Electric System (BES). Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition.

1. Reliability Coordinator personnel who perform the BES company-specific Real-time reliability related tasks of a Reliability Coordinator;
2. Balancing Authority personnel who perform the BES company-specific Real-time reliability-related tasks of a Balancing Authority;
3. Transmission Operator personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator;
4. Transmission Owner personnel who have the capability to control Transmission Facilities using Supervisory Control and Data Acquisition (SCADA); or
5. Generator Operator personnel who perform the reliability tasks of a Generator Operator.

Likes 0	
Dislikes 0	

Response

2. Language throughout Attachment 1 of CIP-002-Y that referred to the "functional obligations" of the different Registered Entities has been replaced with specific references to Control Centers that are either operated by or owned by the relevant Registered Entities. This change was incorporated given that the NERC Functional Model is no longer being actively maintained. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal. Does the change introduce reliability gaps to the Registered Entities? If it does, please provide your rationale.

Ryan Olson - Portland General Electric Co. - 5, Group Name PGE Group

Answer	No
Document Name	

Comment

PGE is in alignement with comments provided by EEI.

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

Mike Magruder - Avista - Avista Corporation - 1

Answer	No
Document Name	

Comment

We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
NAGF disagrees with the change to "owned by" or "operated by". The language refocuses CIP-002 to categorizing systems based on what organization owns or operates the facility they reside within and could lead to unintended consequences. One such consequence is that this change could cause BES Cyber Systems to not be categorized based on the system's function and potential impact to the BES. We understand the SDT reasoning for this proposed change is the NERC Functional Model is no longer maintained, however Sections 5A and 5B of NERC's ROP make statements such as "All industry participants responsible for or intending to be responsible for, the following ***functions*** must register with NERC through the Organization Registration process." Therefore, we do not see an issue that requires changing the language from the concept of performing a function to one of organization ownership/operation.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon is aligning with the EEI in response to this question.	
Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon is aligning with the EEI in response to this question.	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS supports EEI's suggested revisions to CIP-002 Attachment 1, criterion 1.1 through 1.5, which separates criterion for TO and TOP in addition to adding focus to the functions performed in the criterion. AZPS supports the inclusion of Transmission Owners in CIP-002 Attachment 1, criterion 1.3.	
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 the Edison Electric Institute.	
Likes 0	

Dislikes 0	
Response	
Beth Smail - AEP - 1,3,5,6 - MRO,Texas RE,RF	
Answer	No
Document Name	
Comment	
AEP agrees with some of EEI's concerns and recommend refinements to the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Jennifer Tidwell - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company is in agreement with EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy supports EEI and NAGF comments.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Avista supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No

Document Name	
Comment	

Item 7: The addition of the phrasing 'operated by' in Criteria 1.2-1.4 'operated by' instead of 'used to perform the functional obligations of' does not address the present-day situation in one NERC region where multiple different RCs have appointed an RC agent or other non-RC Registered Entity to host the real-time RC functions at the non-RC's Control Center. These RC do not operate their own Control Center, but instead the agent Entity operates it. This occurs either with RC Agent entity personnel performing the RC function, or the RC personnel occupying a single desk and console within the rest of the larger Control Center owned and operated by the Agent. The previous 'functional obligations' language was robust enough to address this; if it must be eliminated in places other than just for the edited 2.12 TOP criteria, suggest instead you reference the standard families/standards/requirements which comprise the real-time function of each registration outside the TOP. Alternatively, leaving the 'Functional Obligation' language intact for the criteria (outside of 2.12) would also remedy this issue.

Item 8: In Attachment 1, Heading 2. Medium Impact Rating (M), the additional phrasing added *"…equipment as described in criteria 2.1 through 2.10"* adds an additional term (*equipment*) which is ambiguous and seems to reduce clarity compared the previously used phrasing. Was this change precipitated by the field test or a specific SAR item, since it wasn't previously proposed? Are there specific devices or installations that were included or excluded previously that this change addresses? An alternative could be replacing "associated with any equipment" to "associated with Facilities, system, group of Elements, or Control Center as described in criteria 2.1 through 2.13:". In addition, this removes the ambiguity created by not having an introduction for criteria 2.11 to 2.13.

Item 9: In Attachment 1, Criteria 2.11, 2.12, and 2.13 the deletion of the phrase *'that is not already included in High Impact Rating above'* will likely result in double classification of many Control Centers as both containing both High and Medium Impact BCSes; is that a needed or desired outcome? If so, is there a reason that the language "…not included in Sections 1 and 2 above…" remains for Low Impact, or should that also be removed?

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	

Dominion Energy supports EEI comments.

Likes 0	
Dislikes 0	
Response	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI understands the SDTs efforts to remove references to the functional model, but the provided revisions could be interpreted in unintended ways for entities with multiple registrations. Further, the term "operated by" is not necessarily representative of the functions being performed. As an example, if an entity is energizing a DC line and it is used at both sites, that could be interpreted as both sites "operated by" the entity and it is not clear how the criteria would apply. While EEI supports the inclusion of Transmission Owners, it would be clearer to separate criterion 1.3 into separate criterion for TOP and TO.

EEI suggests the following revisions in bold face:

1.1 Each Control Center or backup Control Center **performing** Reliability Coordinator **functions.**

1.2 Each Control Center or backup Control Center **performing** Balancing Authority **functions**: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3 Each Control Center or backup Control Center **performing** Transmission Operator **functions** for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center owned by a Transmission Owner for one or more assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.5 Each Control Center or backup Control Center **performing** Generator Operator **functions** for one or more assets that meet criterion 2.1, 2.3, 2.6, or 2.9."

EEI supports the inclusion of Transmission Owners in CIP-002 Attachment 1, which addresses an identified gap in applicability.

Likes 0	
Dislikes 0	
Response	
Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	Comment Form--2021-03_Unofficial_Comment_Form--Submitted 5-15-24.pdf
Comment	

NB Power supports NPCC comments, see attached.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
In the technical rationale, link functional obligations to “capabilities and reliability tasks” as its replacement. The NERC Functional Model should not be referenced in the technical rationale since it is not an active document. TFIST questions why Generator Owner is not included when it meets the capabilities benchmark similar to Transmission Owner.	
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	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	

Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Agree with comments from EEI.	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	
PNM and TNMP agree with EEI comments and vote	
Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NEE support EEI's comments: EEI understands the SDTs efforts to remove references to the functional model, but the provided revisions could be interpreted in unintended ways for entities with multiple registrations. Further, the term "operated by" is not necessarily representative of the functions being performed. As an example, if an entity is energizing a DC line and it is used at both sites, that could be interpreted as both sites "operated by" the entity and it is not clear how the criteria would apply. While EEI supports the inclusion of Transmission Owners, it would be clearer to separate criterion 1.3 into separate criterion for TOP and TO.

EEI suggests the following revisions in bold face:

"1.1 Each Control Center or backup Control Center operated by a **performing** Reliability Coordinator **functions.**

1.2 Each Control Center or backup Control Center operated by a **performing** Balancing Authority **functions**: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3 Each Control Center or backup Control Center ,operated by a **performing** Transmission Operator or owned by a Transmission Owner, **functions** for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center owned by a Transmission Owner for one or more assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 **1.5** Each Control Center or backup Control Center operated by a **performing** Generator Operator **functions** for one or more assets that meet criterion 2.1, 2.3, 2.6, or 2.9."

EEI supports the inclusion of Transmission Owners in CIP-002 Attachment 1, criterion 1.3, which addresses an identified gap in applicability.

Likes 0	
Dislikes 0	
Response	

Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	

Comment	
CEHE believes the revisions could be misinterpreted for entities with multiple registrations. The term "operated by" may not accurately represent the functions being performed by entities. CEHE supports the inclusion of the Transmission Owners in CIP-002 Attachment 1, but suggests separating criterion 1.3 into separate criteria for TOP and TO. The current revisions include Reliability Coordinator, Balancing Authority, Transmission Owner, and Generator Operator functions.	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	No
Document Name	
Comment	
Supporting EEI comments.	
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 and NAGF's comments: EEI understands the SDTs efforts to remove references to the functional model, but the provided revisions could be interpreted in unintended ways for entities with multiple registrations. Further, the term "operated by" is not necessarily representative of the functions being performed. As an example, if an entity is energizing a DC line and it is used at both sites, that could be interpreted as both sites "operated by" the entity and it is not clear how the criteria would apply. While EEI supports the inclusion of Transmission Owners, it would be clearer to separate criterion 1.3 into separate criterion for TOP and TO.	

EEI suggests the following revisions in bold face:

"1.1 Each Control Center or backup Control Center **performing** Reliability Coordinator **functions.**

1.2 Each Control Center or backup Control Center **performing** Balancing Authority **functions**: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3 Each Control Center or backup Control Center **performing** Transmission **functions** for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center owned by a Transmission Owner for one or more assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

(*remove:* 1.4) **1.5** Each Control Center or backup Control Center **performing** Generator Operator **functions** for one or more assets that meet criterion 2.1, 2.3, 2.6, or 2.9."

EEI supports the inclusion of Transmission Owners in CIP-002 Attachment 1, criterion 1.3, which addresses an identified gap in applicability.

NAGF's comments: NAGF disagrees with the change to "owned by" or "operated by". The language refocuses CIP-002 to categorizing systems based on what organization owns or operates the facility they reside within and could lead to unintended consequences. One such consequence is that this change could cause BES Cyber Systems to not be categorized based on the system's function and potential impact to the BES. We understand the SDT reasoning for this proposed change is the NERC Functional Model is no longer maintained, however Sections 5A and 5B of NERC's ROP make statements such as "All industry participants responsible for or intending to be responsible for, the following ***functions*** must register with NERC through the Organization Registration process." Therefore, we do not see an issue that requires changing the language from the concept of performing a function to one of organization ownership/operation.

Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 1	
Likes 0	
Dislikes 0	

Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No
Document Name	
Comment	

FirstEnergy supports EEI comments which state:
EEI understands the SDTs efforts to remove references to the functional model, but the provided revisions could be interpreted in unintended ways for entities with multiple registrations. Further, the term "operated by" is not necessarily representative of the functions being performed. As an example, if an entity is energizing a DC line and it is used at both sites, that could be interpreted as both sites "operated by" the entity and it is not clear how the criteria would apply. While EEI supports the inclusion of Transmission Owners, it would be clearer to separate criterion 1.3 into separate criterion for TOP and TO.

EEI suggests the following revisions in bold face:

"1.1 Each Control Center or backup Control Center a **performing** Reliability Coordinator **functions.**

1.2 Each Control Center or backup Control Center a **performing** Balancing Authority **functions**: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3 Each Control Center or backup Control Center p**erforming** Transmission Operator or owned by a Transmission Owner, **functions** for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 Each Control Center or backup Control Center owned by a Transmission Owner for one or more assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.5 Each Control Center or backup Control Center **performing** Generator Operator **functions** for one or more assets that meet criterion 2.1, 2.3, 2.6, or 2.9."

EEI supports the inclusion of Transmission Owners in CIP-002 Attachment 1, criterion 1.3, which addresses an identified gap in applicability.

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	
In the technical rationale, link functional obligations to “capabilities and reliability tasks” as its replacement. The NERC Functional Model should not be referenced in the technical rationale since it is not an active document. TFIST questions why Generator Owner is not included when it meets the capabilities benchmark similar to Transmission Owner.	
Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	
Response	

Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	No
Document Name	
Comment	
See comments by NCPA Marty Hostler	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
see comments by NCPA Marty Hostler	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	

NCPA's response is related to the proposed language for Impact Rating Criteria (IRC) 2.11 only

Background:

The current effective Standard CIP-002-5.1a IRC 2.11 includes a very import qualifier to determine if a generators' net Real Power (nRP) is required to be included in a GOP Control Center's (CC) IRC 2.11 nRP calculation. The qualifier is "used to perform the functional obligation of" the Generator Operator for an aggregate highest rated nRP capability...

This qualifier is important because if a GOP does not perform any GOP functional obligations for a particular generator then that generator's nRP is not required to be included in the GOP CC aggregate nRP calculation. Non-BES generators do not require a GOP to operate them. Unregistered operators of non-BES generations do not "perform functional obligations of a GOP for non-BES generators and neither do GOPs. Consequently, under the current CIP-002-5.1a IRC 2.11 a GOP is not required to include non-BES generators in their GOP CC aggregate nRP assessment.

Additionally, requiring a GOP to include non-BES generation in their CC aggregate nRP assessments would violate NERC Marketing Principles. The first NERC Marketing Principle states "A reliability standard shall not give any market participant an unfair competitive advantage." Forcing a GOP to include a non-BES generator's nRP in a GOP's IRC 2.11 aggregate calculation violates this principle and gives unregistered operators of non-BES generation an unfair competitive advantage.

Discussion regarding proposed CIP-002-Y.

The project SAR requires the SDT to clarify "perform the functional obligation of" throughout the CIP-002-5.1a Attachment 1 Criteria. However, instead of clarifying it, the SDT opted to eliminate this language. The SDT's rationale for this removal is based on the technical justification that "The NERC Functional Model is no longer actively maintained," as detailed in the preceding question 2 and proposed technical rationale documents.

If the Functional Model is not being maintained and not used anymore, then there are no GOP functional obligations anymore. Obviously, if there are no GOP functional obligation anymore, then GOPs are not performing them for any generator. This means there is no generation to aggregate for the existing CIP-002-5.1a IRC 2.11 Criterion, rendering its preservation unnecessary.

We consider the proposed IRC 2.11 to be a newly introduced, arbitrary criterion lacking any technical foundation. We need the SDT to provide the justification for this newly revised IRC, if it is to be included in the revised Standard, and provide a justification for the 1500MW threshold. Simply only providing a rationale for removing "perform the functional obligation of" is not acceptable to us and is not what the SAR told them to do. We expect and need a Technical Rationale of this new IRC and the justification of the 1500 MW threshold.

We suggest three alternatives.

1. Remove IRC 2.11 entirely from the Standard's Attachment 1.

2. State that Generation Facilities or BES Generators only, are to be included in the GOP CC IRC 2.11 aggregate nRP calculation.

3. Replace "perform the functional obligation of" with "perform the reliability tasks of a GOP for generation Facilities that aggregate to, or above, a

nRP threshold of 1500MW". This is consistent with the proposed GOP CC definition.	
Likes 0	
Dislikes 0	
Response	
Marie Potter - Marie Potter On Behalf of: Alison MacKellar, Constellation, 5, 6; Kimberly Turco, Constellation, 5, 6; - Marie Potter	
Answer	Yes
Document Name	
Comment	
Constellation agrees with replacing "functional obligations" with references to Control Centers that are either operated by or owned by the relevant Registered Entity.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren believes there is little to no impact regarding this change.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes

Document Name	
Comment	
The use of the term “used by and located at” is a good change that clarifies which Cyber Systems are in scope of the definition. The change in terms from “functional obligation” to “operated by” / “owned by” are good changes that clarify the scope of applicable Cyber Assets.	
Likes 0	
Dislikes 0	
Response	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
The language “operated by a…” changes the current language “used to perform the functional obligations of the…..” in Impact Rating Criteria Section 1 and Section 2. This is out of the SAR scope for RC, BA, and GOP. Although this is out of scope of the SAR, this does not introduce reliability gaps to the Registered Entities.	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Tacoma Power agrees with the proposed changes.	
Likes 0	

Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	Yes
Document Name	
Comment	
The use of the term “used by and located at” is a good change that clarifies which Cyber Systems are in scope of the definition. The change in terms from “functional obligation” to “operated by” / “owned by” are good changes that clarify the scope of applicable Cyber Assets.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Katrina Lyons - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Neville - Western Area Power Administration - 1,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 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	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
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) for question #2.	
Likes 0	
Dislikes 0	
Response	
Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	
Document Name	
Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	
Response	

3. The SDT intentionally constructed the exclusion clause within criteria 2.12 of Attachment 1 of CIP-002-Y to require an entity to measure gross export from their defined group of contiguous transmission Elements (GCTE). This accounts for both generation output and flow-through the GCTE. It ensures that an entity is unable to define a GCTE that contains significant generation that supports the BES or with significant flow-through that impacts the BES. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
The language in Criteria 2.12 Exclusion does not specify that an entity can only identify one GCTE. As currently written, an entity may choose to create multiple GCTEs each limited by the 75MW at gross export.	
Likes 0	
Dislikes 0	
Response	

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	No
Document Name	
Comment	
Transmission lines operated at <100kV are not part of the BES and should not be included in the aggregate weighted value model.	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No

Document Name	
Comment	
see comments by NCPA Marty Hostler	
Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	No
Document Name	
Comment	
See comments by NCPA Marty Hostler	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	No
Document Name	
Comment	
See question 1	
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 appreciates the SDTs attempt to address our feedback related to the aggregate weighted table by updating the table header to "Voltage Value of a BES Transmission Line", but the change does not sufficiently address the identified concern. The table header could easily be missed and could be interpreted to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center. EEI suggests the inclusion of clarifying language in the form of an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C of the Rules of Procedure as BES Transmission Lines. EEI generally supports the Exclusion Clause, but notes that terms such as "group of contiguous transmission Elements (GCTE)" may not be well understood. While there is content explaining the intention of the SDT in the Technical Rationale, a defined term may be more appropriate to ensure that Exclusion Clause is consistently applied by entities using it.	
Likes 0	
Dislikes 0	
Response	
Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5	
Answer	No
Document Name	
Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	

Comment	
Ameren believes there should be clarity on any asset less than 100kv, included in Criterion 2.12, per BES exception included in the NERC Rules of Procedure. We also support EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE is in support of the comment as submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
The FERC bright line criteria for a low impact BES Facility is 100kV. Line voltage below 100kV is not considered a transmission Facility and part of the Bulk Electric System for NERC CIP-002 standard. Any lines below 100kV should not be assigned a value in consideration for the aggregate weight for Transmission as they are not defined by FERC as a transmission Facility. GCTE is not a NERC-defined term. Additionally, is the question "….is unable to define GCTE…" or was this to read "….is able to define GCTE.."?	
Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE supports EEI's comments: EEI appreciates the SDTs attempt to address our feedback related to the aggregate weighted table by updating the table header to "Voltage Value of a BES Transmission Line", but the change does not sufficiently address the identified concern. The table header could easily be missed and could be interpreted to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center. EEI suggests the inclusion of clarifying language in the form of an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C of the Rules of Procedure as BES Transmission Lines. EEI generally supports the Exclusion Clause, but notes that terms such as "group of contiguous transmission Elements (GCTE)" may not be well understood. While there is content explaining the intention of the SDT in the Technical Rationale, a defined term may be more appropriate to ensure that Exclusion Clause is consistently applied by entities using it.	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	
PNM and TNMP agree with EEI comments and vote	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	

Answer	No
Document Name	
Comment	
Agree with Comments from EEI.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric d/b/a CenterPoint Energy Indiana South (SIGE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
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	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI appreciates the SDTs attempt to address our feedback related to the aggregate weighted table by updating the table header to "Voltage Value of a BES Transmission Line", but the change does not sufficiently address the identified concern. The table header could easily be missed and could be interpreted to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center. EEI suggests the inclusion of clarifying language in the form of an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C of the Rules of Procedure as BES Transmission Lines. EEI generally supports the Exclusion Clause, but notes that terms such as "group of contiguous transmission Elements (GCTE)" may not be well understood. While there is content explaining the intention of the SDT in the Technical Rationale, a defined term may be more appropriate to ensure that Exclusion Clause is consistently applied by entities using it.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No

Document Name	
Comment	

Item 11: Does the creation of the Exclusion, GCTE, and export measure create an implied requirement for their identification and computation on a cyclical basis, and retain evidence of such computation if the Exclusion is used? How will such a cycle align with the 15 calendar month cycle in CIP-002-5.1a R2? If an entity doesn't desire to utilize the Exclusion, could the requirement allow them to conservatively 'opt in' and not capture the evidence of GCTE/75MW non-exceedance?

Item 12: Is there a 'Performance-Reset Period' implied in the gross export hourly values over a 12-month period? In other words, if exports exceeded 77MW for a single hour in a single 12-month period, would the expectation be that the Control Center be classified as containing Medium Impact BCSes immediately, with the implementation plan for changes started? Or if the exceedance didn't reoccur in the 12 month period following, would the Exclusion reset?

Item 13: Strongly recommend the SDT add at least one specific example in writing in the CIP-002 Implementation Plan to show how an exceedance of the Exclusion following the CIP-002 timing requirements would play out, including the T+ dates as the timeline went along - given this complex situation which drew a number of questions on the SDT web event.

Item 14: The Exclusion mentions that the 75 MW gross export from the GCTE excludes EEA conditions. In the case where it occurred, would this non-EEA export be treated as a 'planned change'?

Item 15: How does the 75MW Exclusion criteria align with NERC's current and future efforts to update registration and compliance standards for Inverter Based Resources? Instead of a fixed number, could it be tied/pointed to a registration criteria?

Likes 0	
Dislikes 0	
Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	

Cleco agrees with EEI comments.

Likes 0	
Dislikes 0	
Response	

Robert Follini - Avista - Avista Corporation - 3	
Answer	No
Document Name	
Comment	
Avista supports EEI comments	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
Duke Energy, while not initially opposed to modification of the criteria, does not see a reliability benefit to constructing an exclusion clause. Duke Energy supports EEI comments that “group of contiguous transmission Elements (GCTE)” may not be well understood.	
Likes 0	
Dislikes 0	
Response	
Jennifer Tidwell - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company is in agreement with EEI's comments.	
Likes 0	
Dislikes 0	

Response	
Beth Smail - AEP - 1,3,5,6 - MRO,Texas RE,RF	
Answer	No
Document Name	
Comment	
AEP agrees with some of EEI's concerns and recommend refinements to the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, 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	
Salt River Project (SRP) is in agreement with the definition change and the proposed changes to Criteria 2.12. However, we feel that generally speaking, measuring the flow through for a utility is done on schedules in the Western interconnection and smaller Transmission Operators would have to have existing metering infrastructure to support 2.12.	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	

AZPS supports EEI's suggestions regarding the inclusion of a specific Exclusion for all transmission lines below 100kv, except those identified through Appendix 5C of the Rules of Procedure as BES Transmission Lines.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon is aligning with the EEI in response to this question.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon is aligning with the EEI in response to this question.	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	No

Document Name	
Comment	
We support EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports EEI's comments.	
Likes 0	
Dislikes 0	
Response	
Ryan Olson - Portland General Electric Co. - 5, Group Name PGE Group	
Answer	No
Document Name	
Comment	
PGE is in alignement with comments provided by EEI.	
Likes 0	
Dislikes 0	
Response	

Marty Hostler - Northern California Power Agency - 4	
Answer	Yes
Document Name	
Comment	
No Comment	
Likes 0	
Dislikes 0	
Response	

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
SMUD agrees with the proposed changes to criteria 2.12, however, we are not sure if the “aggregate weighted value” includes generation tie-lines (e.g. gen-ties). The Standards Drafting Team should answer this question in their next reply to comments or the final ballot.	
Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
In the question, was it intentional to state that "It ensures that an entity is UNABLE to define..."? Or should that have been "… able to define…"?	

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

No Additional Comments.

Likes 0	
Dislikes 0	

Response

Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	Yes
Document Name	Comment Form--2021-03_Unofficial_Comment_Form--Submitted 5-15-24.pdf

Comment

NB Power supports NPCC comments, see attached.

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	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
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	
Jeffrey Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
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	
Tyler Schwendiman - ReliabilityFirst - 10	
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	
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 Neville - Western Area Power Administration - 1,6	
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	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Katrina Lyons - Georgia System Operations Corporation - 3,4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	
Eversource supports EEI's comments on this question.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE is concerned there could be an instance where the transmission facility is considered “medium” under Attachment 1, 2.6 but that Control Center (that operates the facility as a TOP) could exclude that facility under Exclusion under 2.12. Texas RE recommends that Transmission Control Center operators that operate facilities classified as medium (or high) cannot exclude that facility in 2.12.	
Likes 0	
Dislikes 0	
Response	

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison	
Answer	
Document Name	
Comment	
Supporting EEI comments.	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	
Document Name	
Comment	
Not Applicable	
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) for question #3.	
Likes 0	

Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
N/A	
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 is not commenting on Question 3 as Criteria 2.12 of Attachment 1 does not apply to Generator Owners/Generator Operators.	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	
Document Name	
Comment	

NST has no comment

Likes 0	
Dislikes 0	

Response

4. Provide any additional comments for the standard drafting team to consider, if desired.	
Jodirah Green - ACES Power Marketing - 1 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	
Comment	
ACES would like to thank the SDT for it's hard work.	
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	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	
Document Name	
Comment	
See EEI's comments.	

Likes 0	
Dislikes 0	

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer	
Document Name	

Comment

NST is concerned about the fact the SDT SEEMS to be not entirely satisfied with the changes industry is now being asked to approve. This concern is informed by Slide 8 of the April 26, 2024 webinar, which states:

" The SDT has identified the following items to revisit as a team after the current commenting period concludes:
> Consider an alternate approach to defining Control Center that more clearly separates the physical location of operating personnel from the location of Cyber Assets
> Monitor progress of parallel effort to define 'Cyber System' and consider use in the Control Center definition in place of 'Cyber Asset'
>Evaluate impacts associated with changes to the Control Center definition and replacing language in CIP-002 related to 'functional obligations'
>Review the CIP-002 Criterion 2.12 exclusion language to ensure the intent of the SDT is clear and the scope is adequately limited"

NST expects that, subsequent to this ballot, the SDT will post any substantive changes for industry review and approval.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

NAGF is concerned with the proposed changes to the Control Center definition and the new "used by and located at" header in CIP-002 Attachment 1 before criterion 2.11. The concern is there will be unintended consequences leading to over-categorization of BES Cyber Systems (BCS), particularly in some GOP Control Centers. The flow is now explicit that individual BCS will inherit an impact rating based solely on the MW total of the "facility" in which they reside, without regard to the potential impact of any single BCS. In this case with criterion 2.11, if 1500MW is controlled out of the entire ‘facility’, it assumes that is done with one monolithic BCS and therefore the facility total and the BCS impact are one and the same. It does not take into account facilities that may fall into the Control Center definition that may, for example, have numerous individual systems that monitor and can control solar sites vs. wind sites, etc. If a new system is added to the “facility” to monitor and control a 75MW BESS, with this construct of “used by and located at” that individual system is medium impact as it must inherit the total rating of the facility in which it sits. The assumption that a facility always equates to a monolithic BCS is no longer the case. CIP-002 is the categorization of BCS based on each BCS’s potential impact and it should not assign impact ratings based solely on the room in which the system is located.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon is aligning with the EEI in response to this question.

Likes 0	
Dislikes 0	

Response

Gladys DeLaO - CPS Energy - 1,3,5

Answer	
Document Name	

Comment

No additional comments for the SDT to consider

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3	
Answer	
Document Name	
Comment	
Exelon is aligning with the EEI in response to this question.	
Likes 0	
Dislikes 0	
Response	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	

Response	
Jennifer Tidwell - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	
Southern Company is in agreement with EEI's additional comments.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy thanks the Drafting Team for their continued effort to incorporate feedback.	
Likes 0	
Dislikes 0	
Response	
Robert Follini - Avista - Avista Corporation - 3	
Answer	
Document Name	
Comment	
Avista supports EEI comments	

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) for question #4.

In addition, Evergy is concerned about future applications of this revised Control Center definition in regards to a registered entity's use of cloud or AI solutions. By moving to a concept that any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time, the drafting team has potentially unintentionally limited future use of these technologies. Evergy believes that cloud service and AI vendors will not be willing to classify all of their facilities that could potentially house Cyber Assets used to monitor and control the BES in real-time as Control Centers and subsequently be subject to all of the CIP standards associated with that classification. As an example, a cloud provider could have multiple data centers across the US, or the world, that have physical virtual host severs that a Virtual Cyber Asset used for BES monitoring or control could be hosted on. Evergy would encourage the drafting team to consider the future of computing, including cloud, AI, and quantum computing, as they look at further revisions of the standard to determine how they could possibly be incorporated to allow for future use of these technologies.

For the drafting team's reference, DOE and the National Labs have recently published the following documents that the drafting team might want to consider when looking into the technology that could be used in BES Cyber Systems of the future and how those would be impacted by the NERC Glossary definition of Control Center.

https://www.energy.gov/sites/default/files/2024-04/DOE%20CESER_EO14110-AI%20Report%20Summary_4-26-24.pdf

https://www.anl.gov/sites/www/files/2024-04/AI-for-Energy-Report_APRIL%202024.pdf

https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-35735.pdf

Evergy is also concerned about impacts to the new CIP-015-1 standard's Implementation Plan. That plan states, "All Responsible Entities with applicable systems located at Control Centers and backup Control Centers identified pursuant to CIP-002-5.1(a) Requirement R1 Parts 1.1. and 1.2. shall initially comply with the requirements in CIP-015-1 for those Control Centers upon the effective date of Reliability Standard CIP-015-1." This implementation plan was intended to provide a phased in approach to implementing INSM systems first at high and medium w/ ERC Control Centers for the BES Cyber Systems ESPs in their associated data centers. The second phase would allow additional time for installation in non-Control Center environments like substations and generation facilities. Evergy would urge the drafting team to consider any unintended consequences their changes to the Control Center definition may have on CIP-015-1's Implementation Plan.

Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	

Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	

Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	
Document Name	
Comment	
None	

Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	

Item 16: Consider removing the paragraph at the end of Page 2 around street addresses as it could have far-reaching effects beyond just the scope of this project. Many BES Transmission Elements comprising Transmission Facilities are located at substations without any street addresses but simply a GPS coordinate pair, and some BES Generation Facilities may share a single street address but contain multiple different types of generation prime movers with disparate methods of control.   Suggest a return the previously used “Attachment 1 Overall Application item” included on page 23-24, or a more comprehensive treatment on location to include geographic, electrical, legal boundary/property ownership, and fenceline delineations which are commonly seen around larger or shared facilities.

Item 17: Consider indicating/labelling explicitly that the example diagrams apply exclusively to the newly proposed Criterion 2.12 and its Exclusion and not generally to other Attachment Criteria such as 1.3, 2.4, 2.5, etc. Some of the GCTE concepts presented could lead to incorrect conclusions in non-2.12 criteria, especially those pertaining to Facilities operating above 300kV.

Item 18: On Pages 3-4, shifting the location/substation owner between Entity A and C in examples 1, 2, and 3 makes the example harder to follow.

Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	

Please refer to the comments from EEI for additional comments.

Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	
Document Name	
Comment	

EEI recognizes that there are many Standards Development Projects in progress and that there may be conflicts with definitions or concepts between projects because of timing. We encourage NERC and SDTs to consider options to limit the number of ballot periods when SDTs are aware of challenges or issues that are not addressed by the current draft and are likely to lead to failed ballots. We encourage NERC and SDTs to consider other mechanisms available for receiving actionable, timely feedback from industry such as informal comment periods, industry outreach, and webinars.

Additionally, if it is the intention of the Standard Drafting Team to expand the scope of the Control Center definition to include the scenarios described in EEI's response to Question 1, we request revisions to the implementation plan to allow a minimum of 48 months for the Control Center definition and modifications to CIP-002. The additional time will help Entities reassess and determine the actions necessary to become compliant.

Likes 0	
Dislikes 0	

Response

Fon Hiew - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	
Document Name	Comment Form--2021-03_Unofficial_Comment_Form--Submitted 5-15-24.pdf
Comment	

NB Power supports NPCC comments, see attached.

Likes 0	
Dislikes 0	

Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	
Document Name	
Comment	
The use of “only BES Cyber Systems that meet this criterion are each discrete shared BES Cyber Systems that could” statement in Attachment 1, part 2.1 and 2.2 can cause confusion and TFIST proposes rewording these statements. If the thought was to add systems that are redundant this is already address in the BES Cyber Asset definition which excludes redundancy as a consideration. Suggest removing the word discrete or shared. For low impact in the first paragraph, it states, “BES Cyber Assets” …” used by and located at an of the Control Centers or backup Control Centers” Which denotes that a low assets has to be at a Control Center or backup Control Center but, parts 3.1 -3.6 seems to contradict this statement and include other facilities. TFIST proposes a rewording to align the initial sentence and parts 3.1-3.6. The SDT should provide clarity on exception monitoring, reporting, and implementation related to “The gross export is based on the hourly integrated values for the most recent 12-month period.” • When is exceeding the threshold an “unplanned change”, allowing for a 2-year implementation and when is it a “planned change” requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center loses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then loses the exemption, if there are no other medium impact programs in place, do they always get 2 years to either implement the plan or pray that they gain the exemption before the implementation period is over?	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	
Document Name	
Comment	
agree with the additional comments from EEI.	
Likes 0	
Dislikes 0	
Response	

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3

Answer	
Document Name	
Comment	

PNM and TNMP agree with EEI comments and vote

Likes 0	
Dislikes 0	

Response

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	
Comment	

NEE supports EEI's comments: EEI recognizes that there are many Standards Development Projects in progress and that there may be conflicts with definitions or concepts between projects because of timing. We encourage NERC and SDTs to consider options to limit the number of ballot periods when SDTs are aware of challenges or issues that are not addressed by the current draft and are likely to lead to failed ballots. We encourage NERC and SDTs to consider other mechanisms available for receiving actionable, timely feedback from industry such as informal comment periods, industry outreach, and webinars.

Additionally, if it is the intention of the drafting team to bring new facilities into scope under the Control Center definition, such as maintenance facilities and other scenarios as described in EEI's response to Question 1, EEI is concerned about the proposed implementation plan time frames and requests consideration for revising it to 36-48 months at a minimum.

Additionally, if it is the intention of the Standard Drafting Team to expand the scope of the Control Center definition to include the scenarios described in EEI's response to Question 1, we request revisions to the implementation plan to allow a minimum of 48 months for the Control Center definition and modifications to CIP-002. The additional time will help Entities reassess and determine the actions necessary to become compliant.

Likes 0	
Dislikes 0	

Response

David Jendras Sr - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

Ameren supports EEI's comments on this question.

Likes 0	
Dislikes 0	

Response

Michelle Pagano - Con Ed - Consolidated Edison Co. of New York - 5

Answer	
Document Name	

Comment

Supporting EEI comments.

Likes 0	
Dislikes 0	

Response

Carver Powers - Utility Services, Inc. - 4

Answer	
Document Name	

Comment

Recommend restructuring Section 3 in the proposed Attachment 1 to be more concise.

USV proposes restructuring this section to be written similar to:

3. Low Impact Rating (L)

3.1 BES Cyber Systems not included in Sections 1 or 2 above that are used by and located at any of the Control Centers or backup Control Centers.

3.2 BES Cyber Systems not included in Sections 1 or 2 above that are associated with any equipment as described in criteria 3.2.1 through 3.2.5:

3.2.1. Transmission stations and substations.

3.2.2. Generation resources.

3.2.3 Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.2.4 RAS that support the reliable operation of the BES.

3.2.5 For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Technical rationale does not use the NERC definition of Facilities on pages 2 and 3. In example 1 Entity A controls at a minimum 3 Facilities because each of the circuit breakers and the transmission line at a minimum are NERC defined Facilities.

The proposed language “it is generally expected that the Facilities will have separate street addresses.” Is incorrect based on the NERC definition of Facility.

The use of “only BES Cyber Systems that meet this criterion are each discrete shared BES Cyber Systems that could” statement in Attachment 1, part 2.1 and 2.2 can cause confusion. Propose rewording these statements. If the thought was to add systems that are redundant, this is already addressed in the BES Cyber Asset definition which excludes redundancy as a consideration. Suggest removing the word discrete or explaining this in the technical rationale.

Likes 0	
Dislikes 0	

Response

Dermot Smyth - Con Ed - Consolidated Edison Co. of New York - 1, Group Name Con Edison

Answer	
Document Name	

Comment

Supporting EEI comments.	
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 agrees with EEI's additional comments: EEI recognizes that there are many Standards Development Projects in progress and that there may be conflicts with definitions or concepts between projects because of timing. We encourage NERC and SDTs to consider options to limit the number of ballot periods when SDTs are aware of challenges or issues that are not addressed by the current draft and are likely to lead to failed ballots. We encourage NERC and SDTs to consider other mechanisms available for receiving actionable, timely feedback from industry such as informal comment periods, industry outreach, and webinars. Additionally, if it is the intention of the drafting team to bring new facilities into scope under the Control Center definition, such as maintenance facilities and other scenarios as described in EEI's response to Question 1, EEI is concerned about the proposed implementation plan time frames and requests consideration for revising it to 36-48 months at a minimum. Additionally, if it is the intention of the Standard Drafting Team to expand the scope of the Control Center definition to include the scenarios described in EEI's response to Question 1, we request revisions to the implementation plan to allow a minimum of 48 months for the Control Center definition and modifications to CIP-002. The additional time will help Entities reassess and determine the actions necessary to become compliant.	
Likes 0	
Dislikes 0	
Response	
Jason Chandler - Con Ed - Consolidated Edison Co. of New York - 6	
Answer	
Document Name	
Comment	

See question 1

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

FirstEnergy supports EEI's response, which states:

Additionally, if it is the intention of the drafting team to bring new facilities into scope under the Control Center definition, such as maintenance facilities and other scenarios as described in EEI's response to Question 1, EEI is concerned about the proposed implementation plan time frames and requests consideration for revising it to 36-48 months at a minimum.

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

The use of "only BES Cyber Systems that meet this criterion are each discrete shared BES Cyber Systems that could" statement in Attachment 1, part 2.1 and 2.2 can cause confusion and TFIST proposes rewording these statements. If the thought was to add systems that are redundant this is already address in the BES Cyber Asset definition which excludes redundancy as a consideration. Suggest removing the word discrete or shared.

For low impact in the first paragraph, it states, "BES Cyber Assets" …" used by and located at an of the Control Centers or backup Control Centers" Which denotes that a low assets has to be at a Control Center or backup Control Center but, parts 3.1 -3.6 seems to contradict this statement and include other facilities. TFIST proposes a rewording to align the initial sentence and parts 3.1-3.6.

The SDT should provide clarity on exception monitoring, reporting, and implementation related to “The gross export is based on the hourly integrated values for the most recent 12-month period.”

When is exceeding the threshold an “unplanned change”, allowing for a 2-year implementation and when is it a “planned change” requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center loses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then loses the exemption, if there are no other medium impact programs in place, do they always get 2 years to either implement the plan or pray that they gain the exemption before the implementation period is over?

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

There is a timing issue between the recently ballot-approved CIP-002-7 under Project 2016-02 and this project. While the updates to both are not incompatible, it will result (if CIP-002-Y is approved) in two competing, but approved, versions of the standard, which will need to be merged. The MRO NSRF recommends that NERC either avoid opening competing projects to update the same standard at the same time, or release a statement when drafts are released on how and when it intends to merge the two should both be approved.

Additionally, the MRO NSRF would suggest that NERC begin to plan a path forward to address emerging technologies such as cloud computing and the use of AI.

Likes 0	
Dislikes 0	

Response

James Keele - Entergy - 3

Answer	
Document Name	

Comment	
* Section 2 of Attachement 1 states that "... any equipment as described in criteria 2.1 through 2.10". However, there are 3 more bullets to section 2, 2.11, 2.12, and 2.13. The paragraph between 2.10 and 2.11 regarding 2.11 through 2.13 appears to be part of 2.10. Consider moving that paragraph to the top of section 2 so that it is more clear. * In section 2.5 of Attachment 1, is there an intended different between the weight for lines less that 200kV and lines 500kV and above? One has "(not applicable)" but the other has "0 (N/A)", which appear to be the same but are stated differently. * In section 3 of Attachment 1, consider moving the information regarding sections 3.2 through 3.6 to the top of section 3 rather than between bullets / sections.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE previously indicated that risk cannot be adequately determined by quantity of transmission lines operated. Texas RE acknowledges the drafting team's response that the medium impact rating categorization may not be appropriate for all Control Centers. Since there is still risk posed to the reliable operations of the bulk power system, Texas RE recommends the creation of an additional inclusion criteria in Attachment 1, section 2: Each Control Center or backup Control Center, operated by a Transmission Operator or Owned by a Transmission Owner, that monitors or controls transmission Elements interconnected with generating units at any number of plant locations, where the aggregate highest rated net Real Power capability of the preceding 12 calendar months is equal to or exceeding 1500 MW in a single Interconnection. For example, if the Transmission Operator is operating three substations that are each interconnected with a 600 MW generation resource then the total aggregate Real Power capability is 1800 MW and the BCS located at the Transmission Operator's Control Center should be categorized as medium impact.	

Likes 0	
Dislikes 0	
Response	
Tyler Schwendiman - ReliabilityFirst - 10	
Answer	
Document Name	
Comment	

1. In the technical rationale there is a statement “This language aligns with the present GOP Control Center definition.” However, “GOP Control Center” is not in the NERC Glossary of Terms and this statement should be modified/clarified. “This language aligns with the GOP reference in the current Control Center definition.”
2. Consider replacing “equipment” with “asset” in Impact Rating Criteria 3.1. “Control Centers and backup Control Centers containing BES Cyber Systems not included in Sections 1 or 2 above that are associated with any **asset** as described in criteria 3.2 through 3.6.”
3. Consider modifying the formatting of the paragraph immediately preceding IRC 2.11 (beginning with “Each BES Cyber System, not included in Section 1 above,…”) to clarify that this paragraph is not part of IRC 2.10. A change as simple as outdenting the paragraph to the same level as the IRC numbers would accomplish this. This would match the format of the paragraph that precedes IRC 2.1.

Likes 0	
Dislikes 0	
Response	
Michael Whitney - Northern California Power Agency - 3, Group Name NCPA	
Answer	
Document Name	
Comment	

See comments by NCPA Marty Hostler

Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
see comments by NCPA Marty Hostler	
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	
There seems to be an error in the Technical Rational, Example 1 on page 3. Should the example be written as, "In Example 1, Entity A has control of breakers at both ***ends*** of a Transmission Line, which constitutes a Transmission Facility." Currently, it's written as, "In Example 1, Entity A has control of breakers at both ***lines*** of a Transmission Line, which constitutes a Transmission Facility."	
Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	
Document Name	
Comment	

Prior to Criteria 2.11 in Attachment 1, the following lead-in statement should not be indented: “Each BES Cyber System, not included in Section 1 above, used by and located at any of the Control Centers or backup Control Centers described in criteria 2.11 through 2.13:”	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	
Document Name	
Comment	
If the existing proposal is approved then additional lead time is needed for GOP's that have CC's which may get reclassified to a higher classification. We suggest three years. For TO’s and TOP’s the SDT included clarification that only BES Transmission was to be included in assessments however, for GOPs in IRC 2.11, the SDT deleted “perform to functional obligation of” but did not clarify that GOPs too, only needed to consider BES generation in their assessments. Thus, implying that GOPs may have to consider all types of generation (non-BES and BES) regardless. This violates NERC Marketing Principles by providing unregistered operators of non-BES generation an unfair competitive advantage. Further, the SDT's proposal suggests a GOP, in IRC 2.11, that Controls and Monitors 1500 MW of BES and non-BES generation is a Medium Impact CC. But, a TO or TOP, per IRC 2.12, that Controls and Monitors 5,999 MVA of BES only transmission, is a Low Impact CC. We need the SDT to help us understand why a GOP, that Controls and Monitors four (4) times less, will be held to a higher standard.	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	
Document Name	
Comment	

Eversource supports EEI's comment regarding the posting of projects when the STD is aware of issues or challenges.	
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	

Comments received from Steve Rueckert/WECC

1. Based on industry comments, the SDT has modified the Control Center definition. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☒ No

   Comments:

While we concur with the modified Control Center definition is part of addressing issues identified in the SAR scope, we note the following –

a) As of the 04/01/2024 version of NERC Complete Standard set, **Control Center** or "control center" is instanced 312 times; over 180 of those references are within the CIP standards, and not always consistently (Capitalized where appropriate, non-capitalized where it should be). The other 132 references are instanced outside the CIP standards.

b) Wherever in the existing standards the term **Control Center** is used as a glossary term there could be impact to auditability and enforceability, depending on the context of use and if that context changes when the term Control Center is changed.

c) Just one example of illustrating need for thorough review:

   i) There is a potential conflict with the change and a term that is not proposed for change "System Operator".

   ii) System Operator is a NERC glossary term tied inexorably to the existing definition of "Control Center", as it is referenced per the capitalized term. The scope of meaning may be changed if the Control Center term is changed while System Operator is not. Just one simple example, but it is important, because one way to interpret CIP-002-Y it is wittingly or unwittingly defining a functional system operator in contrast to the existing term in the glossary.

2. Language throughout Attachment 1 of CIP-002-Y that referred to the "functional obligations" of the different Registered Entities has been replaced with specific references to Control Centers that are either operated by or owned by the relevant Registered Entities. This change was incorporated given that the NERC Functional Model is no longer being actively maintained. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal. Does the change introduce reliability gaps to the Registered Entities? If it does, please provide your rationale.

   ☒ Yes
   ☐ No

   Comments:

3. The SDT intentionally constructed the exclusion clause within criteria 2.12 of Attachment 1 of CIP-002-Y to require an entity to measure gross export from their defined group of contiguous transmission Elements (GCTE). This accounts for both generation output and flow-through the GCTE. It ensures that an entity is unable to define a GCTE that contains significant generation that supports the BES or with significant flow-through that impacts the BES. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

   ☒ Yes
   ☐ No

   Comments:

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

   Comments:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Response to Comments

Project 2021-03 CIP-002

August 2024

RELIABILITY | RESILIENCE | SECURITY




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Table of Contents

Introduction

NERC Project 2021-03 proposes revisions to the Control Center definition and CIP-002-8 Criterion 2.12 in Attachment 1. CIP-002-8 provides "bright-line" criteria for applicable Responsible Entities to categorize their Bulk Electric Systems (BES) Cyber Systems based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the BES. The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers (TOCCs) performing the functional obligations of a Transmission Operator (TOP), specifically those that meet medium impact criteria, and clarifying the language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.

There were 67 sets of responses, including comments from approximately 166 different people from approximately 100 companies representing 10 of the industry Segments.

Additional information is available on the project page.

Background

Based on industry feedback, the drafting team (DT) modified the Control Center definition along with CIP-002-8. Please refer to the CIP-002-8 Technical Rationale document 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, Dominique Love (Dominique.love@nerc.net).

Thank You

The drafting team thanks industry for your time in reviewing the proposed CIP-002-8 standard and providing comments and proposals for the DT's consideration. All comments received have been reviewed and discussed. Response to comments have been drafted in a summary response.

Control Center Definition

Control Center Definition

Currently approved definition:

> ***Control Center -*** *One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.*

Draft 1[1] proposed definition:

> ***Control Center -*** *One or more rooms where a responsible entity hosts operating personnel to monitor and control the Bulk Electric System (BES) in real-time, as described below, including any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time. Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units.*
>
> 1. *Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;*
> 2. *Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;*
> 3. *Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations;*
> 4. *Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or*
> 5. *Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more locations in real-time.*

Draft 2[2] proposed definition:

> ***Control Center -*** *One or more facilities used by the operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time, and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time. Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition.*
>
> 1. *Reliability Coordinator personnel who perform the BES company-specific Real-time reliability-related tasks of a Reliability Coordinator;*
> 2. *Balancing Authority personnel who perform the BES company-specific Real-time reliability-related tasks of a Balancing Authority;*
> 3. *Transmission Operator personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations;*
> 4. *Transmission Owner personnel who have the capability to control Transmission Facilities at two or more locations using Supervisory control and Data Acquisition (SCADA); or*

[1] Posted for comment and ballot period September 26 – November 9,2023

[2] Posted for comment and ballot period April 2 – May 16, 2024

5. *Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.*

Industry Comments

- Data center language and related field asset exclusion
    - Disagree with revising the Control Center definition to reference "any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time" and prefer reverting to the original "associated data centers" language.
    - The "any facilities" language could be broadly interpreted to encompass facilities that were not intended by the drafting team, and clarity regarding the term 'data center' could be achieved via other means such as technical rationale, implementation guidance, or other supporting materials.
- Revert to 'hosting operating personnel' instead of 'used by operating personnel'
    - The proposed language is inappropriately over-broad and has the potential to errantly identify Transmission Facilities as Control Centers, a function they were never intended to execute.
- Language applicable to Reliability Coordinator (RC), Balancing Authority (BA), TOP and Generator Operator (GOP) should remain the same as it is today, including exclusive use of real-time as opposed to Real-time.
- Focus on facilities that TO have the capability to control via Supervisory Control and Data Acquisition (SCADA) as using an existing defined term helps with differentiation for different types of control that may exist.

DT Response

After considering the industry comments received, the DT has identified that the changes previously proposed to the Control Center definition that were intended to address existing areas of ambiguity such as use of the term 'associated data center' and further defining reliability tasks performed by registered entities created additional challenges. The DT believes that the work needed to resolve these additional challenges that were raised by the industry extends beyond the scope of the portion of the 2016-02 SAR that was assigned to the 2021-03 DT. For this reason, the DT has reverted to the original Control Center definition language as it applies to the RC, BA, TOP and GOP. The DT has added a specific provision to the definition that applies to the TO to ensure registered entities properly identify TOCCs based on the capability to control transmission Facilities at two or more locations in real-time using SCADA.

The DT believes that the new language is better suited to addressing the portion of the 2016-02 SAR that was assigned to the 2021-03 DT, as it more clearly indicates that monitoring capabilities and the performance of reliability related tasks are not relevant to the identification of a TOCC.

Below provides the updated proposed Control Center definition that will be posted with Draft 3.

> ***Control Center*** *- One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.*
>
> *OR*
>
> *One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers and excluding field Cyber Assets used for telemetry.*

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 3.

Administrative

SAR Scope

There were many industry concerns that were related to items that extend beyond the scope of the portion of the 2016-02 Standard Authorization Request (SAR) that was assigned to the 2021-03 DT.

Industry Comments

- Recommendation to create an additional inclusion criteria in Attachment 1 2.6 for interconnection of a certain aggregate rated net Real Power capability for the TOP and TO
- Concern expressed regarding an instance where the transmission facility is considered "medium" under Attachment 1 2.6; however, the Control Center (that operates the facility at a TOP) could exclude that facility under the 2.12 Exclusion
- Suggest removing the word 'discrete' or shared
- Recommendation to modify language "perform the functional obligation of" to specifically exclude non-BES generation for the GOP from the aggregation of relevant criteria

DT Response

The SAR allows the DT to recommend clarification of applicability of requirements for a TOCC that has the capability to control BES Elements, the definition of Control Center and the language "perform the functional obligations of" throughout the Attachment 1 criteria. The SAR does not extend to proposing any additional inclusion clauses in relation to the risk associated with TOP or TO monitoring and controlling transmission Elements interconnected with generating units. Further, the SAR does not extend to addressing issues with criterion 2.6, or its associated references throughout Attachment 1. The DT does note that there are two additional SARs under separate consideration that are specifically intended to address the concerns with criterion 2.6. Finally, the incorporation of the term 'discrete' in Attachment 1 criteria 2.1 and 2.2 is not a red-line proposed by the DT. This change was separately proposed by the 2016-02 DT in order to address the associated implementation guidance currently included in CIP-002-5.1a.

While the portion of the 2016-02 SAR that was assigned to the 2021-03 DT includes addressing the language "perform the functional obligations of" throughout CIP-002, the DT has identified that certain modifications to the language that may fundamentally impact interpretation by entities other than TOP and TO falls beyond the scope of the SAR.

"Perform the Functional Obligations of"

Some entities expressed concern with 'operated by' not being representative of the functions performed. It does not account for scenarios where multiple different RCs have appointed an RC agent or other non-RC RE to host the real-time RC functions.

DT Response

The DT recognizes the challenges identified by commenters with the previously proposed 'owned by' and 'operated by' language. For these reasons, the DT has proposed an alternative approach that consists of replacing the term 'functional obligations' with the term 'reliability tasks'. This is viewed as an improvement over use of 'functional obligations' as it eliminates the obsolete reference to the NERC Functional Model. It also aligns CIP-002 language with the existing language of the Control Center definition and is viewed as a net neutral change that will not further complicate the challenges surrounding aggregation of BES versus non-BES resources for calculating net Real Power. Further, the concept of 'reliability tasks' is an established concept that is described in the existing CIP-002 technical rationale and will be retained in the updated technical rationale document.

TOP and TO Functions

Entities request separating TOP and TO functions into two different criteria.

DT Response

The DT modified the Control Center definition to specifically identify the unique functions of the Transmission Owner. Once a TOP or TO has identified the Control Center per the definition, the DT believe that the combined criteria in Attachment 1 are adequate to disposition the BES Cyber Systems used by and located at the Control Center. In addition, the DT believes that a single criterion 1.3 and a single criterion 2.12 that applies to both TOP and TO is clearer and more concise.

Use of 'equipment' in the Preface Language

Entities commented that that the use of 'equipment' in the preface language of Attachment 1 is ambiguous and reduces clarity compared to the previous language.

DT Response

The DT agrees that the use of the phrase 'associated with any equipment as described in' is introducing unnecessary ambiguity. For this reason, the DT has reverted to the original language 'associated with any of the following'. Further, the drafting team has recognized that its modifications to the preface language for the criteria that specifically address Control Centers and backup Control Centers using the phrase "used by and located at" will not impact application of CIP-002 Requirement R1 that already requires identification of high impact and medium impact BES Cyber Systems "at each asset". While concerns have been raised about future applications for cloud computing and similar technologies, holistic modifications to the requirements and attachments are outside the scope of the 2021-03 SAR. Therefore, the DT has reverted to the original language.

Criteria 2.11, 2.12, and 2.13 and Preface Language

Commenters expressed concern that the deletion of the phrase 'that is not already included in High Impact Rating above' in Attachment 1, Criteria 2.11, 2.12, and 2.13 will likely result in double classification of many Control Centers as both containing both High and Medium Impact BCS.

DT Response

The preface language in Section 2 of Attachment 1 includes language 'not included in Section 1 above'. The preface language in Section 3 of Attachment 1 includes language 'not included in Sections 1 and 2 above'. With this preface language, there is no need to include the language ‘not included in High Impact Rating above’ in each individual criterion in Sections 2 and 3 of Attachment 1. The preface language ensures that there is no double classification of the BES Cyber Systems used by and located at Control Centers or backup Control Centers.

Criteria 2.12 Table

Commenters mentioned that the table header could be interpreted to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center. It was suggested the inclusion of clarifying language in the form of an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C of the NERC Rules of Procedure as BES transmission lines.

DT Response

The DT considered adding a note to the table that specifically references back to Appendix 5C of the NERC Rules of Procedure, which is the exception process through which a Transmission Line as defined in the NERC Glossary of Terms that is less than 100 kV could be identified as part of the BES. The DT believes that the specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered. Any non-BES Transmission Lines would not be included in the aggregate weighted value calculation. Additional detail regarding the inclusion of lines <100kV in the Aggregate Weighted Value calculation can be found in the Technical Rationale.

Exclusion Clause

Commenters expressed concerns in regards to the exclusion clause. Comments are listed below:

Industry Comments

- Group of Contiguous Transmission Elements (GCTE) is not well understood, consider a new defined term
- Language is not currently clear that an entity can only identify one GCTE
- Clarity is needed regarding whether the Aggregate Weighted Value includes tie-lines
- Requirements for metering infrastructure to support the 2.12 exclusion may be challenging for smaller entities

DT Response

The DT has reworded the exclusion clause in an attempt to clarify and simplify the concept. Further, the team replaced the concept of a group of contiguous transmission Elements (GCTE) with the concept of a group of contiguous Elements to clarify that the group of Elements may contain transmission Elements and non-transmission Elements. The use of an acronym, i.e. GCE, within the standard was removed. The DT elected not to create a new defined term because it would only apply in the Technical Rational. This approach is consistent with the approach taken to define a Local Network within the Bulk Electric System definition, as opposed to creating a separate definition. The new language proposed by the DT more specifically states that an entity may only exclude a single group of contiguous Elements. In addition, the 75 MW gross export limitation was changed to 75 MWh to correctly represent an hourly integrated gross export, and not an instantaneous measurement within the hour.

Regarding the inclusion of generation tie-lines in the aggregate weighted value calculation, the DT has modified criterion 2.12 to parallel the language in criterion 2.5. This more clearly states DT’s intention that the aggregate weighted value is only calculated for each BES Transmission Line that is connected to two or more Transmission stations or substations.

An entity may choose for themselves whether or not to pursue an exclusion under the documented exclusion clause. With respect to an entity’s use of the exclusion clause, it is the entity’s responsibility to determine the most appropriate method to demonstrate their compliance and to retain the evidence necessary. Further, the Technical Rational clarifies that Criterion 2.12 does not require entities to install meters specifically for the purpose of calculating the hourly integrated gross export. Entities may choose to install metering for this purpose, or they may pursue other avenues such as using SCADA data to calculate the hourly integrated value.

Implementation Plan

Planned vs. Unplanned

Entitles expressed concerns in regards to timeframe for implementation for the Control Center definition and modifications to CIP. There were suggestions to increase from 24-month implementation window to 36 months and/or 48 months. The additional time will help entities reassess and determine the actions necessary to become compliant.

DT Response

The DT considered increasing the phased-in implementation date for CIP-002-8, Requirement R1, Attachment 1 Criteria 2.12 from 24 months; however, the DT elected to retain 24 month window as it aligns with the established 24 month window that is currently provided to Responsible Entities who identify their first high impact or medium impact BES Cyber System. The DT does not see the justification for extending the implementation window. Further, given that the earliest effective date of CIP-002-8 is April 1, 2026 (aligning with the earliest possible effective date of CIP-002-7), entities will have adequate time to evaluate impacts before the 24 month window commences.

Alignment with Other CIP related Projects

Entities expressed concerns about the syncing implementation plans together.

DT Response

As the 2016-02 version of CIP-002-7 has passed final ballot, the next posting of CIP-002-8 will be sequenced accordingly. The revised implementation plan will reflect the natural sequencing of the two projects.

Technical Rationale

Industry Comments

Many entities request the technical rationale document be updated regarding many aspects of the standard.

DT Response

See the updated Technical Rationale, which addresses industry comments requesting additional clarifications or justification.

Reminder

Standards Announcement

Project 2021-03 CIP-002

Additional Ballots and Non-binding Poll Open through May 16, 2024

Now Available

The additional ballots and non-binding poll for **CIP-002-Y — Cyber Security — BES Cyber System Categorization** are open through **8 p.m. Eastern, Thursday, May 16, 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 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 2021-03 CIP-002” in the Title and Description Boxes.

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

Standards Announcement

Project 2021-03 CIP-002

Formal Comment Period Open through May 16, 2024

Now Available

A formal comment period for **draft two of CIP-002-Y — Cyber Security - BES Cyber System Categorization**, is open through **8 p.m. Eastern, Thursday, May 16, 2024**.

The drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

There are currently two drafting teams working on modifications to CIP-002-5.1a. The Project 2021-03 standard drafting team is posting modifications as CIP-002-Y to differentiate its work from Project 2016-02 Modifications to CIP Standards (CIP-002-7).

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.

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

Next Steps

Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **May 7 – 16, 2024**.

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

For more information or assistance, contact 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 2021-03 CIP-002" in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/322)
Ballot Name: 2021-03 CIP-002 CIP-002-Y AB 2 ST
Voting Start Date: 5/7/2024 12:01:00 AM
Voting End Date: 5/16/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 263
Total Ballot Pool: 297
Quorum: 88.55
Quorum Established Date: 5/16/2024 12:47:44 PM
Weighted Segment Value: 47.72

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	84	1	36	0.514	34	0.486	0	5	9
Segment: 2	7	0.3	2	0.2	1	0.1	0	3	1
Segment: 3	69	1	32	0.525	29	0.475	0	5	3
Segment: 4	15	1	7	0.583	5	0.417	0	2	1
Segment: 5	73	1	28	0.509	27	0.491	0	4	14
Segment: 6	44	1	14	0.389	22	0.611	1	1	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.4	0	0	4	0.4	0	1	0
Totals:	297	5.7	119	2.72	122	2.98	1	21	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
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		Negative	Comments Submitted
1	American Transmission Company, LLC	Amy Wilke		Affirmative	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	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Negative	Comments Submitted
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	City of College Station	Stacy Engelmann		None	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	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		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Affirmative	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		None	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		Negative	Comments Submitted
1	MEAG Power	David Weekley	Rebika Yitna	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		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Negative	Comments Submitted
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	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 Pend Oreille County	Angela Hall		Negative	Third-Party Comments
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	Sarah Blankenship	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Third-Party Comments
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Negative	Comments Submitted
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
1	Xcel Energy, Inc.	Eric Barry		Affirmative	N/A
2	California ISO	Darcy O'Connell		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	John Galloway	Negative	Third-Party Comments
2	Midcontinent ISO, Inc.	Bobbi Welch	Adrian Harris	Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
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		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	BC Hydro and Power Authority	Ming Jiang		Negative	Comments Submitted
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Negative	Comments Submitted
3	Bonneville Power Administration	Ron Sporseen		Affirmative	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	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner		Abstain	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
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		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
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		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	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		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Third-Party Comments
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Silicon Valley Power - City of Santa Clara	VAL GUZMAN		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	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	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Negative	Comments Submitted
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Acciona Energy North America	Truong Le		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Third-Party Comments
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
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		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Negative	Comments Submitted
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	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	Marie Potter	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Decatur Energy Center LLC	Megan Melham		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
5	Imperial Irrigation District	Tino Zaragoza		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	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		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Michael Johnson	Affirmative	N/A
5	Pattern Operators LP	George E Brown		None	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Negative	Comments Submitted
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		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		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted

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	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	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		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	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		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Clay Walker	Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco	Marie Potter	Negative	No Comment Submitted
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
6	Great River Energy	Brian Meloy		None	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		Affirmative	N/A
6	Manitoba Hydro	Kelly Bertholet		Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		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		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments
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		Affirmative	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	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Negative	Comments Submitted
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
10	New York State Reliability Council	Wesley Yeomans		Negative	Third-Party Comments
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Negative	Comments Submitted

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/322)
Ballot Name: 2021-03 CIP-002 Implementation Plan AB 2 OT
Voting Start Date: 5/7/2024 12:01:00 AM
Voting End Date: 5/16/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 256
Total Ballot Pool: 290
Quorum: 88.28
Quorum Established Date: 5/16/2024 1:02:32 PM
Weighted Segment Value: 58.73

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	82	1	39	0.582	28	0.418	0	6	9
Segment: 2	7	0.3	3	0.3	0	0	0	3	1
Segment: 3	67	1	33	0.559	26	0.441	0	5	3
Segment: 4	15	1	8	0.667	4	0.333	0	2	1
Segment: 5	72	1	30	0.577	22	0.423	0	5	15
Segment: 6	43	1	18	0.486	19	0.514	0	1	5
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	4	0.1	0	0	1	0.1	0	3	0
Totals:	290	5.4	131	3.171	100	2.229	0	25	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
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
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		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Affirmative	N/A
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Carly Miller	Negative	Comments Submitted
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Negative	Third-Party Comments
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	City of College Station	Stacy Engelmann		None	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	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		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Negative	Third-Party Comments
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Affirmative	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	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Affirmative	N/A
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Affirmative	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Third-Party Comments
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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 Pend Oreille County	Angela Hall		Abstain	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	Sarah Blankenship	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Third-Party Comments
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Third-Party Comments
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	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		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	John Galloway	Affirmative	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch	Adrian Harris	Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
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		Negative	Comments Submitted
3	APS - Arizona Public Service Co.	Jessica Lopez		Negative	Comments Submitted
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
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		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Bonneville Power Administration	Ron Sporseen		Affirmative	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	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Bill Garvey		Negative	Comments Submitted
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Negative	Comments Submitted
3	Edison International - Southern California Edison Company	Romel Aquino		Negative	Comments Submitted
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Affirmative	N/A
3	Imperial Irrigation District	George Kirschner		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
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		Affirmative	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		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	David Rivera		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Third-Party Comments
3	Omaha Public Power District	David Heins		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Third-Party Comments
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted
3	PPL - Louisville Gas and Electric Co.	James Frank		None	N/A
3	PSEG - Public Service Electric and Gas Co.	Christopher Murphy		Negative	Third-Party Comments
3	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		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Third-Party Comments
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Negative	Third-Party Comments
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		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	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	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Negative	Third-Party Comments
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Acciona Energy North America	Truong Le		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Negative	Comments Submitted
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		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted
5	BC Hydro and Power Authority	Quincy Wang		Affirmative	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Negative	Comments Submitted
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	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	Marie Potter	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Decatur Energy Center LLC	Megan Melham		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		None	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Third-Party Comments
5	Imperial Irrigation District	Tino Zaragoza		Abstain	N/A
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	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		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Third-Party Comments
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Michael Johnson	Affirmative	N/A
5	Pattern Operators LP	George E Brown		None	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	Platte River Power Authority	Jon Osell		Negative	Third-Party Comments
5	Portland General Electric Co.	Ryan Olson		Abstain	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		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		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Third-Party Comments
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Third-Party Comments
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted
5	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		Affirmative	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		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Negative	Comments Submitted
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	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		Affirmative	N/A
6	Cleco Corporation	Robert Hirchak	Clay Walker	Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco	Marie Potter	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted
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		Affirmative	N/A
6	Manitoba Hydro	Kelly Bertholet		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		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		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		None	N/A
6	Powerex Corporation	Raj Hundal		Affirmative	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Negative	Third-Party Comments
6	PSEG - PSEG Energy Resources and Trade LLC	Laura Wu		Negative	Third-Party Comments
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		Affirmative	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	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Tennessee Valley Authority	Armando Rodriguez		Negative	Comments Submitted
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Showing 1 to 290 of 290 entries

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BALLOT RESULTS

Ballot Name: 2021-03 CIP-002 Non-binding Poll AB 2 NB
Voting Start Date: 5/7/2024 12:01:00 AM
Voting End Date: 5/16/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 2
Total # Votes: 242
Total Ballot Pool: 278
Quorum: 87.05
Quorum Established Date: 5/16/2024 1:22:19 PM
Weighted Segment Value: 53.44

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	78	1	29	0.547	24	0.453	16	9
Segment: 2	7	0.3	2	0.2	1	0.1	2	2
Segment: 3	65	1	26	0.531	23	0.469	13	3
Segment: 4	14	1	7	0.636	4	0.364	2	1
Segment: 5	69	1	23	0.535	20	0.465	12	14
Segment: 6	41	1	14	0.5	14	0.5	6	7
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	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	4	0.2	0	0	2	0.2	2	0
Totals:	278	5.5	101	2.949	88	2.551	53	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
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		Affirmative	N/A
1	Arkansas Electric Cooperative Corporation	Emily Corley		Abstain	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Negative	Comments Submitted
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Micah Runner	Carly Miller	Abstain	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Affirmative	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Negative	Comments Submitted
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		Negative	Comments Submitted
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	N/A
1	Duke Energy	Katherine Street		Negative	Comments Submitted
1	Entergy	Brian Lindsey		Affirmative	N/A
1	Evergy	Kevin Frick	Alan Kloster	Negative	Comments Submitted
1	Eversource Energy	Joshua London		Negative	Comments Submitted
1	Exelon	Daniel Gacek		Negative	Comments Submitted
1	FirstEnergy - FirstEnergy Corporation	Theresa Ciancio		Negative	Comments Submitted
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Negative	Comments Submitted
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz		Abstain	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		None	N/A
1	KAMO Electric Cooperative	Micah Breedlove		None	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Affirmative	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	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		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Negative	Comments Submitted
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Negative	Comments Submitted
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker		None	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Affirmative	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		None	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Negative	Comments Submitted
1	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 Pend Oreille County	Angela Hall		Abstain	N/A
1	Public Utility District No. 1 of Snohomish County	Alyssia Rhoads		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Sacramento Municipal Utility District	Wei Shao	Tim Kelley	Affirmative	N/A
1	Salt River Project	Sarah Blankenship	Israel Perez	Negative	Comments Submitted
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Negative	Comments Submitted
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Negative	Comments Submitted
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Negative	Comments Submitted
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		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	U.S. Bureau of Reclamation	Richard Jackson		Affirmative	N/A
1	Unisource - Tucson Electric Power Co.	Sam Rugel		Abstain	N/A
1	Western Area Power Administration	Ben Hammer		Affirmative	N/A
2	California ISO	Darcy O'Connell		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Affirmative	N/A
2	ISO New England, Inc.	John Pearson	John Galloway	Negative	Comments Submitted
2	Midcontinent ISO, Inc.	Bobbi Welch	Adrian Harris	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	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	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Negative	Comments Submitted
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		Abstain	N/A
3	Bonneville Power Administration	Ron Sporseen		Affirmative	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	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Abstain	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Con Ed - Consolidated Edison Co. of New York	Peter Yost		Affirmative	N/A
3	Dominion - Dominion Virginia Power	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		Affirmative	N/A
3	Evergy	Marcus Moor	Alan Kloster	Negative	Comments Submitted
3	Eversource Energy	Vicki O'Leary		Negative	Comments Submitted
3	Exelon	Kinte Whitehead		Negative	Comments Submitted
3	FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim		Negative	Comments Submitted
3	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner		Abstain	N/A
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		Affirmative	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Muscatine Power and Water	Seth Shoemaker		Affirmative	N/A
3	National Grid USA	Brian Shanahan		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	David Rivera		Negative	Comments Submitted
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney		Negative	Comments Submitted
3	NW Electric Power Cooperative, Inc.	Heath Henry		Affirmative	N/A
3	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	None	N/A
3	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Negative	Comments Submitted
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Affirmative	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Affirmative	N/A
3	Platte River Power Authority	Richard Kiess		Negative	Comments Submitted
3	PNM Resources - Public Service Company of New Mexico	Amy Wesselkamper		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Negative	Comments Submitted
3	Santee Cooper	Vicky Budreau		Abstain	N/A
3	Seminole Electric Cooperative, Inc.	Marc Sedor		Negative	Comments Submitted
3	Sempra - San Diego Gas and Electric	Bryan Bennett		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		Negative	Comments Submitted
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Negative	Comments Submitted
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Negative	Comments Submitted
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	CMS Energy - Consumers Energy Company	Aric Root		Abstain	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Negative	Comments Submitted
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler		Negative	Comments Submitted
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	Ken Habgood		Negative	Comments Submitted
4	Tacoma Public Utilities (Tacoma, WA)	Hien Ho	Jennie Wike	Affirmative	N/A
4	Utility Services, Inc.	Carver Powers		Negative	Comments Submitted
4	WEC Energy Group, Inc.	Matthew Beilfuss		None	N/A
5	Acciona Energy North America	Truong Le		None	N/A
5	AEP	Thomas Foltz		Abstain	N/A
5	AES - AES Corporation	Ruchi Shah		Negative	Comments Submitted
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith		Negative	Comments Submitted
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Abstain	N/A
5	Bonneville Power Administration	Juergen Bermejo		Affirmative	N/A
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	Affirmative	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		Abstain	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	Marie Potter	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		None	N/A
5	Decatur Energy Center LLC	Megan Melham		None	N/A
5	Duke Energy	Dale Goodwine		Negative	Comments Submitted
5	Edison International - Southern California Edison Company	Selene Willis		Negative	Comments Submitted
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A
5	Evergy	Jeremy Harris	Alan Kloster	Negative	Comments Submitted
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Negative	Comments Submitted
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Great River Energy	Jacalynn Bentz		None	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Negative	Comments Submitted
5	Imperial Irrigation District	Tino Zaragoza		Abstain	N/A
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Glenn Barry		Affirmative	N/A
5	Lower Colorado River Authority	Teresa Krabe		Affirmative	N/A
5	LS Power Development, LLC	C. A. Campbell		Abstain	N/A
5	Muscatine Power and Water	Neal Nelson		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Fon Hiew		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		Negative	Comments Submitted
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		None	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Michael Johnson	Affirmative	N/A
5	Pattern Operators LP	George E Brown		None	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	Platte River Power Authority	Jon Osell		Negative	Comments Submitted
5	Portland General Electric Co.	Ryan Olson		Negative	Comments Submitted
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		Abstain	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		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		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Negative	Comments Submitted
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Negative	Comments Submitted
5	Southern Company - Southern Company Generation	Leslie Burke		Negative	Comments Submitted
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		None	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Negative	Comments Submitted
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		Affirmative	N/A
6	Black Hills Corporation	Rachel Schuldt		Abstain	N/A
6	Bonneville Power Administration	Tanner Brier		Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler		Affirmative	N/A
6	Constellation	Kimberly Turco	Marie Potter	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Negative	Comments Submitted
6	Duke Energy	John Sturgeon		Negative	Comments Submitted
6	Entergy	Julie Hall		Affirmative	N/A
6	Evergy	Tiffany Lake	Alan Kloster	Negative	Comments Submitted
6	FirstEnergy - FirstEnergy Corporation	Stacey Sheehan		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Affirmative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Negative	Comments Submitted
6	NiSource - Northern Indiana Public Service Co.	Dmitriy Bazylyuk		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		Negative	Comments Submitted
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Negative	Comments Submitted
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		Negative	Comments Submitted
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		Abstain	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation	Ron Carlsen		Negative	Comments Submitted
6	Southern Indiana Gas and Electric Co.	Kati Barr		Negative	Comments Submitted
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		None	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Negative	Comments Submitted
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Abstain	N/A

Previous 1 Next

Showing 1 to 278 of 278 entries

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:	Modifications to CIP-002 and CIP-014		
Date Submitted:	May 26, 2021 (Reviewed on 5/7/2024)		
SAR Requester			
Name:	Dean LaForest (Reviewed by the 2021-03 Drafting Team)		
Organization:	ISO New England		
Telephone:	413-387-8132	Email:	dlaforest@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?):
This project provides revisions to CIP-002 and CIP-014 to clarify the responsibility of Reliability Coordinators, Planning Coordinators and Transmission Planners in identifying Facilities that warrant consideration under these Reliability Standards. As it relates to the Transmission Planner and Planning Coordinator functions, the language “critical to the derivation of Interconnection Reliability Operating Limits (IROLs)” should be replaced/updated to appropriately identify Facilities that, if somehow compromised, could significantly impact the reliability of the Bulk Electric System (BES). Additionally this project will review the applicability of Facilities identified by the Reliability Coordinator as critical to the derivation of IROLs to CIP-002 and CIP-014.
Purpose or Goal (How does this proposed project provide the reliability-related benefit described above?):
This project provides necessary clarification to identify Facilities identified by Reliability Coordinators, Planning Coordinators and Transmission Planners that warrant consideration under the CIP-002 and CIP-

Requested information
014 Reliability Standards. These clarifications will ensure that responsible entities are provided with the necessary information to appropriately protect these Facilities, and correctly identify the responsible parties that provide the information applicable to the standards.
Project Scope (Define the parameters of the proposed project):
This project will make conforming changes to CIP-002 and CIP-014 as a result of Standard revisions from Project 2015-09. Project 2015-09 revised the requirements for determining and communicating System Operating Limits (SOLs) and IROLs used in the reliable planning and operation of the BES. These revisions necessitate that CIP-002 and CIP-014 be revised to clarify the Functional Entities responsible for communication of Facilities that warrant consideration under the CIP-002 and CIP-014 Reliability Standards. This will include review of criteria/applicability to determine Facilities identified per Attachment 1 of CIP-002 and the Applicability section of CIP-014 for potential revision for responsible entities. This team will work to coordinate with other ongoing CIP development projects to ensure alignment with any changes to definition or standards and requirements.
Detailed Description (Describe the proposed deliverable(s) with sufficient detail for a drafting team to execute the project. If you propose a new or substantially revised Reliability Standard or definition, provide: (1) a technical justification[1] which includes a discussion of the reliability-related benefits of developing a new or revised Reliability Standard or definition, and (2) a technical foundation document (*e.g.,* research paper) to guide development of the Standard or definition):
Revisions to CIP-002 and CIP-014 to include: (1) Identifying Functional Entities that identify Facilities applicable to CIP-002 and CIP-014. (2) Identifying Functional Entities responsible for the communication of the identified Facilities. (3) Applicability sections to be reviewed and revised accordingly. (4) Determine the appropriate Facilities for application of the CIP standard and include due consideration for those planning events that result in System instability, Cascading, or uncontrolled separation as identified in the PC and TP's Planning Assessment for the Near-Term Transmission Planning Horizon. (5) Determine the appropriateness of the identification of Facilities critical to the derivation of IROLs by the RC.
Cost Impact Assessment, if known (Provide a paragraph describing the potential cost impacts associated with the proposed project):
Cost impact of implementation of the proposed Standard is dependent upon the method(s) by which a Responsible Entity chooses to meet any additional Requirements. However, a question will be asked during the SAR comment period to ensure cost aspects are considered.
Please describe any unique characteristics of the BES facilities that may be impacted by this proposed standard development project (*e.g.*, Dispersed Generation Resources):
Submitter asserts there are no unique characteristics associated with BES facilities that will be impacted by this proposed standard development project.

[1] The NERC Rules of Procedure require a technical justification for new or substantially revised Reliability Standards. Please attach pertinent information to this form before submittal to NERC.

Requested information
To assist the NERC Standards Committee in appointing a drafting team with the appropriate members, please indicate to which Functional Entities the proposed standard(s) should apply (*e.g.*, Transmission Operator, Reliability Coordinator, etc. See the most recent version of the NERC Functional Model for definitions):
Reliability Coordinator, Balancing Authority, Transmission Owner, Transmission Operator, Generator Owner, Generator Operator
Do you know of any consensus building activities[2] in connection with this SAR? If so, please provide any recommendations or findings resulting from the consensus building activity.
None.
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 2016-02 Modifications to CIP 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.
None at this time.

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.

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

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
	None identified

For Use by NERC Only

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

Version History

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

Standard Development Timeline

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

Description of Current Draft

This is the third draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023
45-day formal comment period with additional ballot	April 2 – May 16, 2024

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 29 – October 14, 2024
Final ballot	December 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):

Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-8

3. **Purpose:** To identify and categorize BES Cyber Systems (BCS) and their associated BES Cyber Assets (BCA) for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BCS could have on the reliable operation of the Bulk Electric System (BES). Identification and categorization of BCS support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-8:

4.2.3.1. Cyber Systems at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Systems associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3. Cyber Systems, associated with communication networks and data communication links, between the Cyber Systems providing confidentiality and integrity of an ESP that extends to one or more geographic locations.

4.2.3.4. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.5. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. **Effective Dates:** See Implementation Plan for CIP-002

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts 1.1 through 1.3: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** RAS that support the reliable operation of the BES; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BCS according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BCS according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BCS according to Attachment 1, Section 3, if any (a discrete list of low impact BCS is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1.

R2. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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

The 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 Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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

Violation Severity Levels

R #	Violation Severity Levels (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer identified BCS have not been categorized or have been	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent but less than or equal to 10 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high or medium impact BCS, more than 10 percent but less than or equal to 15 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than 15 identified BCS have not been categorized or have been

R #	Violation Severity Levels (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer high or medium BCS have not been identified.	medium impact BCS, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent but less than or equal to 10 percent high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than five but less than or equal to 10 high or medium BCS have not been identified.	medium impact BCS, more than 10 but less than or equal to 15 identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 10 percent but less than or equal to 15 percent high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than 10 but less than or equal to 15 high or medium BCS have not been identified.	incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of high or medium impact BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BCS have not been identified.
R2	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (Part 2.1)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (Part2.1)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (Part 2.1)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 18 calendar months of the previous review. (Part 2.1) OR

R #	Violation Severity Levels (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR The Responsible Entity did not complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (Part 2.2)	OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (Part 2.2)	OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (Part 2.2)	The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (Part 2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Implementation Plan for Project 2021-03
- CIP-002-8 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	5/14/2020	Adopted by the NERC Board of Trustees.	Modified Criterion 2.12.
7	TBD	Virtualization Modifications	

Version	Date	Action	Change Tracking
7	5/9/2024	Adopted by the NERC Board of Trustees.	
8	TBD	Transmission Owners Control Centers Update	

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High impact rating

Each BCS used by and located at any of the following:

1.1. For Reliability Coordinators, each Control Center or backup Control Center used to perform the reliability tasks of the Reliability Coordinator.

1.2. For Balancing Authorities, each Control Center or backup Control Center used to perform the reliability tasks of the Balancing Authority for: 1) generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. For Transmission Operators and Transmission Owners, each Control Center or backup Control Center for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 For Generator Operators, each Control Center or backup Control Center used to perform the reliability tasks of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium impact rating

Each BCS, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher

voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each RAS or automated switching System that operates BES Elements, that, if destroyed, degraded, misused, or otherwise rendered unavailable, would cause one or more IROLs violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing UVLS or UFLS under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. For Generator Operators, each Control Center or backup Control Center, used to perform the reliability tasks of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. For Transmission Operators and Transmission Owners, each Control Center or backup Control Center with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value

per BES Transmission Line" that is monitored and controlled by the Control Center or backup Control Center shown in the table below. Include each BES Transmission Line that is connected between two or more Transmission stations or substations.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:
Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may exclude the BES Transmission Lines that are contained in a single group of contiguous Elements from their "aggregate weighted value" calculation, where a group of contiguous Elements is defined as:

- a group of contiguous Elements emanating from multiple points of connection at 69kV or higher;
- that are operated at less than 300kV; and
- where the gross export does not exceed 75 MWh during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

2.13. For Balancing Authorities, each Control Center or backup Control Center used to perform the reliability tasks of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low impact rating
BCS not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS that support the reliable operation of the BES.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Standard Development Timeline

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

Description of Current Draft

This is the third draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023
45-day formal comment period with additional ballot	April 2 – May 16, 2024

Anticipated Actions	Date
45-day formal comment period with additional ballot	August 29 – October 14, 2024
Final Ballot TOCC	December 2024
Board adoption	December 2024

CIP-002-8 is the combination of Project 2021-03's changes in on top of Project 2016-02's changes for virtualization. The following key describes the origin of changes in CIP-002-8:

Redline Text	Project 2021-03 Draft 3 changes
Redline Text	Project 2016-02 changes (Version 7)

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):

Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-8~~5.1a~~

3. **Purpose:** To identify and categorize BES Cyber Systems (BCS) and their associated BES Cyber Assets (BCA) for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BCS~~BES Cyber Systems~~ could have on the reliable operation of the Bulk Electric System (BES).~~BES.~~ Identification and categorization of BCS~~BES Cyber Systems~~ support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme (RAS) where the RAS~~Special Protection System or Remedial Action Scheme~~ is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

~~**4.1.5. Interchange Coordinator or Interchange Authority**~~

~~4.1.6.~~4.1.5. **Reliability Coordinator**

~~4.1.7.~~4.1.6. **Transmission Operator**

~~4.1.8.~~4.1.7. **Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS~~Each Special Protection System or Remedial Action Scheme where the Special Protection System or Remedial Action Scheme~~ is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-8~~5.1a~~:

4.2.3.1. Cyber Systems~~Assets~~ at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Systems~~Assets~~ associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESP).

4.2.3.3. Cyber Systems, associated with communication networks and data communication links, between the Cyber Systems providing confidentiality and integrity of an ESP that extends to one or more geographic locations.

~~**4.2.3.3.**~~**4.2.3.4.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

~~**4.2.3.4.**~~**4.2.3.5.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**5.**~~ **Effective Dates:** See Implementation Plan for CIP-002

~~1. **24 Months Minimum –** CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~**6. Background:**~~

~~This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.~~

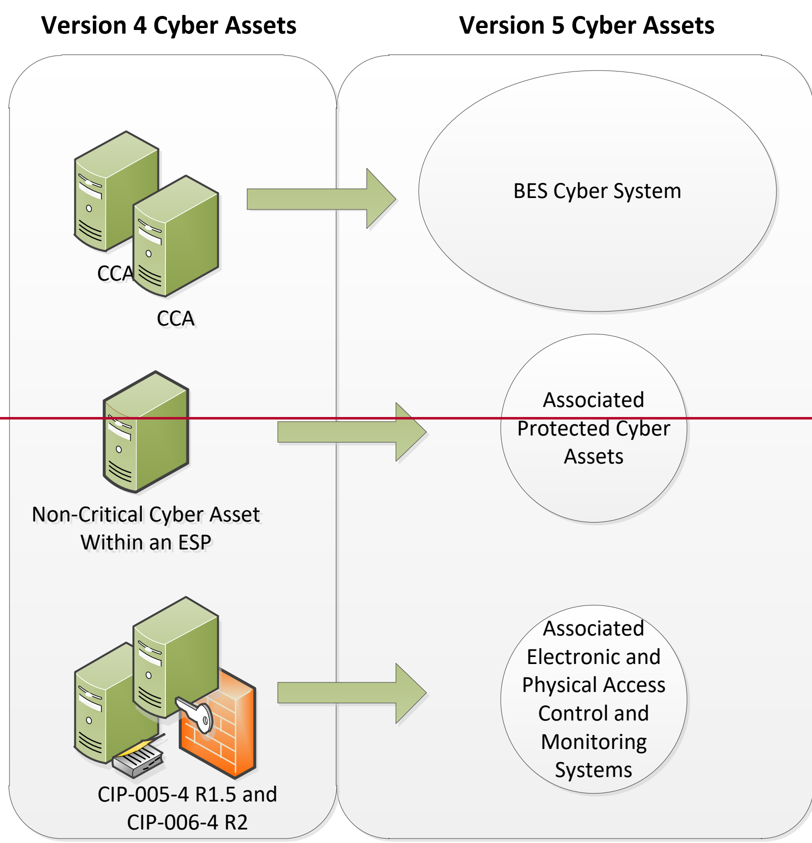
~~Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."~~

5. ~~Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS~~

~~tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~**BES Cyber Systems**~~

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

~~Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.~~

~~It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~Reliable Operation of the BES~~

~~The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.~~

~~Real-time Operations~~

~~One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.~~

~~Categorization Criteria~~

~~The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.~~

~~This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the~~

~~purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.~~

~~**Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems**~~

~~BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:~~

~~**Electronic Access Control or Monitoring Systems ("EACMS")** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.~~

~~**Physical Access Control Systems ("PACS")**– Examples include: authentication servers, card systems, and badge control systems.~~

~~**Protected Cyber Assets ("PCA")** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.~~

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts~~parts~~ 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** RAS~~Special Protection Systems~~ that support the reliable operation of the BES~~Bulk Electric System~~; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BCS~~BES Cyber Systems~~ according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BCS~~BES Cyber Systems~~ according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BCS~~BES Cyber System~~ according to Attachment 1, Section 3, if any (a discrete list of low impact BCS~~BES Cyber Systems~~ is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1~~, and Parts 1.1 and 1.2~~.

R2. Each~~The~~ Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. **Compliance Monitoring Process:**

1.1. Compliance Enforcement Authority:
"~~The Regional Entity shall serve as the~~ Compliance Enforcement Authority" means NERC or the Regional Entity, or any ~~("CEA") unless the applicable~~ entity as otherwise designated~~is owned, operated, or controlled~~ by an Applicable Governmental Authority, in their respective roles of monitoring and/~~the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC~~ or enforcing compliance with mandatory and enforceable Reliability Standards in their respective jurisdictions. ~~other applicable governmental authority shall serve as the CEA.~~

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

The 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 Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program~~Assessment Processes~~:
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

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

~~1.4. Additional Compliance Information~~

- ~~None~~

~~2. Table of Compliance Elements~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-~~85.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Operations Planning~~	~~High~~	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, five	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-8~~5.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			percent or fewer of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, five or fewer identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, five	For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than five percent but less than or equal to 10 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~and BES Cyber Systems~~, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly	For Responsible Entities with more than a total of 100 high or medium impact BCS~~BES Cyber Systems~~, more than 10 percent but less than or equal to 15 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact BCS~~and BES Cyber Assets~~, more than 10 but less than or equal to 15 identified BCS~~BES Cyber Assets~~ have not been categorized or have been incorrectly	BCS~~BES Cyber Systems~~, more than 15 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than 15 identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-8~~5.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			percent or fewer high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, five or fewer high or medium BCS~~BES Cyber Systems~~ have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than five percent but less than or equal to 10 percent high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than five but less than or equal to 10 high or medium BCS~~BES Cyber Systems~~ have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than 10 percent but less than or equal to 15 percent high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than 10 but less than or equal to 15 high or medium BCS~~BES Cyber Systems~~ have not been identified.	and medium impact BCS~~BES Cyber Systems~~, more than 15 percent of high or medium impact BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BCS~~BES Cyber Systems~~ have not been identified.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-8~~5.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	~~Operations Planning~~	~~Lower~~	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (Part 2~~R2~~.1) OR The Responsible Entity did not complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (Part 2~~R2~~.2)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (Part2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (Part 2~~R2~~.2)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (Part 2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (Part 2~~R2~~.2)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 18 calendar months of the previous review. (Part 2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (Part 2~~R2~~.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Implementation Plan for Project 2021-03

~~None.~~

- CIP-002-8 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	5/14/2020	Adopted by the NERC Board of Trustees.	Modified Criterion 2.12.
7	TBD	Virtualization Modifications	

Version	Date	Action	Change Tracking
7	5/9/2024	Adopted by the NERC Board of Trustees.	
8	TBD	-Transmission Owners Control Centers Update	

~~5.1a –~~Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High impact rating~~Impact Rating (H)~~

Each BCS~~BES Cyber System~~ used by and located at any of the following:

1.1. For Reliability Coordinators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Reliability Coordinator.

1.2. For Balancing Authorities, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center ~~used to perform the functional obligations of the Transmission Operator~~ for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 For Generator Operators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium impact rating~~Impact Rating (M)~~

Each BCS~~BES Cyber System~~, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BCS~~BES Cyber Systems~~ that meet this criterion are each discrete~~those~~ shared BCS~~BES Cyber Systems~~ that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BCS~~BES Cyber Systems~~ that meet this criterion are each discrete~~those~~ shared BCS~~BES Cyber~~

~~Systems~~ that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each ~~Special Protection System (SPS), Remedial Action Scheme (~~RAS~~),~~ or automated switching System that operates BES Elements, that, if destroyed, degraded, misused, or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or

cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. For Generator Operators, e~~E~~ach Control Center or backup Control Center~~, not already included in High Impact Rating (H), above,~~ used to perform the reliability tasks~~functional obligations~~ of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per BES Transmission Line” that is monitored and controlled by the Control Center or backup Control Center shown in the table below. Include each BES Transmission Line that is connected between two or more Transmission stations or substations. ~~used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:

Provided that the “aggregate weighted value” calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may exclude the BES Transmission Lines that are contained in a single group of contiguous Elements from their “aggregate weighted value” calculation, where a group of contiguous Elements is defined as:

- a group of contiguous Elements emanating from multiple points of connection at 69kV or higher;
- that are operated at less than 300kV; and

- where the gross export does not exceed 75 MW during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

~~2.12.~~2.13. For Balancing Authorities, e~~E~~ach Control Center or backup Control Center~~, not already included in High Impact Rating (H) above,~~ used to perform the reliability tasks~~functional obligations~~ of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low impact rating~~Impact Rating (L)~~

BCS

~~BES Cyber Systems~~ not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS~~Special Protection Systems~~ that support the reliable operation of the Bulk Electric System.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

~~Guidelines and Technical Basis~~ (Project 2021-03 decided to highlight the title versus the entire section of the GTB. The GTB sections were removed by Project 2016-02.)

~~Section 4 – Scope of Applicability of the CIP Cyber Security Standards~~

~~Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.~~

~~Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.~~

~~Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.~~

~~For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.~~

~~CIP-002-5.1a~~

~~CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."~~

~~The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in~~

~~providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-5.1a. The concept includes a number of named BES reliability operating services. These named services include:~~

~~Dynamic Response to BES conditions~~
~~Balancing Load and Generation~~
~~Controlling Frequency (Real Power)~~
~~Controlling Voltage (Reactive Power)~~
~~Managing Constraints~~
~~Monitoring & Control~~
~~Restoration of BES~~
~~Situational Awareness~~
~~Inter-Entity Real-Time Coordination and Communication~~

~~Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.~~

~~Entity Registration~~	~~RC~~	~~BA~~	~~TOP~~	~~TO~~	~~DP~~	~~GOP~~	~~GO~~
~~Dynamic Response~~		~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Balancing Load & Generation~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Controlling Frequency~~		~~X~~				~~X~~	~~X~~
~~Controlling Voltage~~			~~X~~	~~X~~	~~X~~		~~X~~
~~Managing Constraints~~	~~X~~		~~X~~			~~X~~	
~~Monitoring and Control~~			~~X~~			~~X~~	
~~Restoration~~			~~X~~			~~X~~	
~~Situation Awareness~~	~~X~~	~~X~~	~~X~~			~~X~~	
~~Inter-Entity coordination~~	~~X~~	~~X~~	~~X~~	~~X~~		~~X~~	~~X~~

~~Dynamic Response~~

~~The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:~~

- ~~Spinning reserves (contingency reserves)~~
  - ~~Providing actual reserve generation when called upon (GO,GOP)~~
  - ~~Monitoring that reserves are sufficient (BA)~~
- ~~Governor Response~~
  - ~~Control system used to actuate governor response (GO)~~
- ~~Protection Systems (transmission & generation)~~
  - ~~Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)~~
  - ~~Zone protection for breaker failure (DP, TO, TOP)~~
  - ~~Breaker protection (DP, TO, TOP)~~
  - ~~Current, frequency, speed, phase (TO,TOP, GO,GOP)~~
- ~~Special Protection Systems or Remedial Action Schemes~~
  - ~~Sensors, relays, and breakers, possibly software (DP, TO, TOP)~~
- ~~Under and Over Frequency relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Under and Over Voltage relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Power System Stabilizers (GO)~~

~~Balancing Load and Generation~~

~~The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:~~

- ~~Calculation of Area Control Error (ACE)~~
  - ~~Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)~~
  - ~~Software used to perform calculation (BA)~~
- ~~Demand Response~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP,DP)~~
- ~~Manually Initiated Load shedding~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP, DP)~~

- ~~Non-spinning reserve (contingency reserve)~~
    - ~~Know generation status, capability, ramp rate, start time (GO, BA)~~
    - ~~Start units and provide energy (GOP)~~

~~Controlling Frequency (Real Power)~~

~~The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:~~

- ~~Generation Control (such as AGC)~~
    - ~~ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)~~
    - ~~Software to calculate unit adjustments (BA)~~
    - ~~Transmit adjustments to individual units (GOP)~~
    - ~~Unit controls implementing adjustments (GOP)~~
- ~~Regulation (regulating reserves)~~
    - ~~Frequency source, schedule (BA)~~
    - ~~Governor control system (GO)~~

~~Controlling Voltage (Reactive Power)~~

~~The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:~~

- ~~Automatic Voltage Regulation (AVR)~~
    - ~~Sensors, stator control system, feedback (GO)~~
- ~~Capacitive resources~~
    - ~~Status, control (manual or auto), feedback (TOP, TO,DP)~~
- ~~Inductive resources (transformer tap changer, or inductors)~~
    - ~~Status, control (manual or auto), feedback (TOP,TO,DP)~~
- ~~Static VAR Compensators (SVC)~~
    - ~~Status, computations, control (manual or auto), feedback (TOP, TO,DP)~~

~~Managing Constraints~~

~~Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:~~

- ~~Available Transfer Capability (ATC) (TOP)~~
- ~~Interchange schedules (TOP, RC)~~
- ~~Generation re-dispatch and unit commit (GOP)~~
- ~~Identify and monitor SOL's & IROL's (TOP, RC)~~
- ~~Identify and monitor Flow gates (TOP, RC)~~

~~Monitoring and Control~~

~~Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:~~

- ~~All methods of operating breakers and switches~~
  - ~~SCADA (TOP, GOP)~~
  - ~~Substation automation (TOP)~~

~~Restoration of BES~~

~~The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:~~

- ~~Restoration including planned cranking path~~
  - ~~Through black start units (TOP, GOP)~~
  - ~~Through tie lines (TOP, GOP)~~
- ~~Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)~~
- ~~Coordination (TOP, TO, BA, RC, DP, GO, GOP)~~

~~Situational Awareness~~

~~The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:~~

- ~~Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)~~
- ~~Change management (TOP,GOP,RC,BA)~~
- ~~Current Day and Next Day planning (TOP)~~
- ~~Contingency Analysis (RC)~~
- ~~Frequency monitoring (BA, RC)~~

~~Inter-Entity Coordination~~

~~The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:~~

- ~~Scheduled interchange (BA,TOP,GOP,RC)~~
- ~~Facility operational data and status (TO, TOP, GO, GOP, RC, BA)~~
- ~~Operational directives (TOP, RC, BA)~~

~~Applicability to Distribution Providers~~

~~It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.~~

~~Requirement R1:~~

~~Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.~~

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

~~Attachment 1~~

~~Overall Application~~

~~In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.~~

- ~~When the drafting team uses the term "Facilities", there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.~~
- ~~In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.~~
- ~~It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.~~

~~High Impact Rating (H)~~

~~This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some~~

~~of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.~~

~~The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.~~

~~Additional thresholds as specified in the criteria apply for this category.~~

~~Medium Impact Rating (M)~~

~~Generation~~

~~The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.~~

- ~~Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.~~

  ~~In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.~~

  ~~By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.~~

~~The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.~~

- ~~In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.~~

  ~~If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.~~

  ~~The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.~~

- ~~Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.~~

  ~~IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.~~

- ~~Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.~~

- ~~Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.~~

- ~~Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~Transmission~~

~~The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.~~

- ~~Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.~~

- ~~Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.~~

~~It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.~~

- ~~Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:~~

  - ~~Excluded radial facilities that would only provide support for single generation facilities.~~
  - ~~Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.~~

~~The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.~~

~~Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:~~

- ~~230 kV –> 700 MVA~~
- ~~345 kV –> 1,300 MVA~~
- ~~500 kV –> 2,000 MVA~~
- ~~765 kV –> 3,000 MVA~~

~~In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:~~

- ~~For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate~~

~~connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.~~

- ~~Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.~~

- ~~Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.~~

~~Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.~~

1. ~~The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.~~
2. ~~The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.~~

~~The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.~~

- ~~Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2,~~ ~~**Establish and Communicate System Operating Limits**~~~~, R5.1.1 and R5.1.3.~~

- ~~Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.~~

- ~~Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.~~

- ~~Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.~~

- ~~Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.~~

  ~~This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~In ERCOT, the Load acting as a Resource ("LaaR") Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.~~

~~The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.~~

- ~~Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.~~
- ~~Criterion 2.13 categorizes as Medium Impact those BA Control Centers that "control" 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~Low Impact Rating (L)~~

~~BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.~~

~~Restoration Facilities~~

- ~~Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.~~

  ~~In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.~~

  ~~The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.~~

~~Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.~~

~~BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.~~

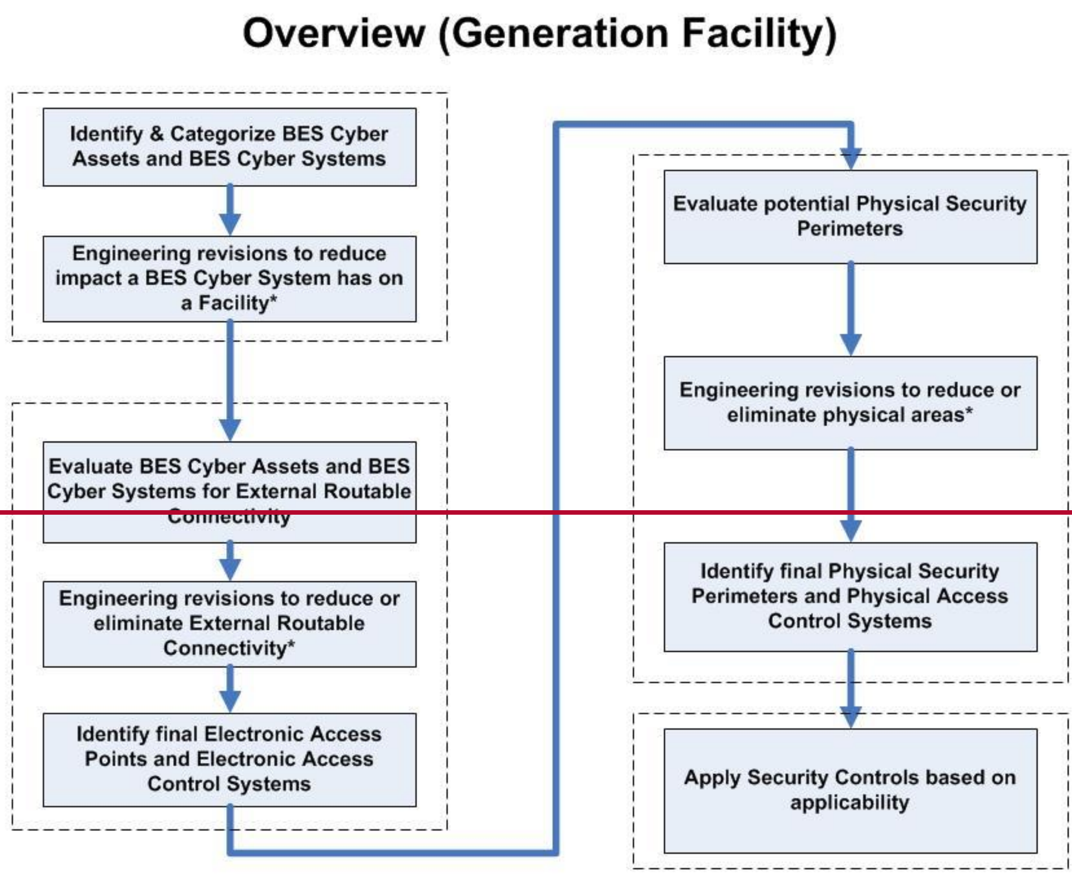
~~Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."~~

- ~~BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.~~

  ~~Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.~~

~~**Use Case: CIP Process Flow**~~

~~The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.~~



* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

~~Rationale:~~

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

~~Rationale for R1:~~

~~BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of "bright-line" criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.~~

~~Rationale for R2:~~

~~The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager's approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.~~

~~5~~	~~11/26/12~~	~~Adopted by the NERC Board of Trustees.~~	~~Modified to coordinate with other CIP standards and to revise format to use RBS Template.~~
~~5.1~~	~~9/30/13~~	~~Replaced "Devices" with "Systems" in a definition in background section.~~	~~Errata~~
~~5.1~~	~~11/22/13~~	~~FERC Order issued approving CIP-002-5.1.~~	
~~5.1a~~	~~11/02/16~~	~~Adopted by the NERC Board of Trustees.~~	
~~5.1a~~	~~12/14/2016~~	~~FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.~~	

~~Appendix 1~~

~~Requirement Number and Text of Requirement~~
~~CIP-002-5.1, Requirement R1~~ ~~R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:~~ ~~i. Control Centers and backup Control Centers;~~ ~~ii. Transmission stations and substations;~~ ~~iii. Generation resources;~~ ~~iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;~~ ~~v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and~~ ~~vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.~~ ~~1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;~~ ~~1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and~~ ~~1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).~~ ~~Attachment 1, Criterion 2.1~~ ~~2. Medium Impact Rating (M)~~ ~~Each BES Cyber System, not included in Section 1 above, associated with any of the following:~~ ~~2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.~~
~~Questions~~
~~Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."~~ ~~The Interpretation Drafting Team identified the following questions in the RFI:~~

~~1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~ ~~2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~ ~~3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~
~~Responses~~
~~Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~ ~~The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)~~ ~~Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:~~ ~~The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~ **~~Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~** ~~The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.~~ ~~The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:~~ ~~Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating~~

~~criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1:~~ ~~**Impact Rating of Generation Resource Shared BES Cyber Systems**~~ ~~for further information and examples.~~

~~**Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?**~~

~~The phrase applies to each discrete BES Cyber System.~~

Standard Development Timeline

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

Description of Current Draft

This is the third~~second~~ draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023
45-day formal comment period with additional ballot	April 2 – May 16, 2024

Anticipated Actions	Date
45-day formal comment period with additional ballot	~~April 2 – May 16, 2024~~ August 29 – October 14, 2024
Final Ballot TOCC	December 2024
Board adoption	December 2024

CIP-002-8 is the combination of Project 2021-03's changes layered on top of Project 2016-02's changes for virtualization. The following key describes the origin of changes in CIP-002-8:

~~Redline Text~~	Project 2021-03 Draft 2 changes
Redline Text	Project 2021-03 Draft 3 changes (Version 8)
Redline Text	Project 2016-02 changes (Version 7)

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):

Control Center - One or more facilities hosting ~~used by the~~ operating personnel ~~described below to~~ that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including ~~and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time. Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition.~~their associated data centers, of:

1) a Reliability Coordinator ~~personnel who perform the BES company-specific Real-time reliability related tasks of a Reliability Coordinator;~~,

2) a Balancing Authority ~~personnel who perform the BES company-specific Real-time reliability-related tasks of a Balancing Authority;~~,

3) a Transmission Operator ~~personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator~~ for t~~T~~ransmission Facilities at two or more locations;

~~4) Transmission Owner personnel who have the capability to control Transmission Facilities at two or more locations using Supervisory Control and Data Acquisition (SCADA);~~ or

~~5~~4) a Generator Operator ~~personnel who perform the reliability tasks of a Generator Operator~~ for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

A. Introduction

1. **Title:** Cyber Security — ~~Bulk Electric System (~~BES~~)~~ Cyber System Categorization

2. **Number:** CIP-002-~~5.1a~~Y8

3. **Purpose:** To identify and categorize BES Cyber Systems (BCS) and their associated BES Cyber Assets (BCA) for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BCS~~BES Cyber Systems~~ could have on the reliable operation of the Bulk Electric System (BES). Identification and categorization of BCS~~BES Cyber Systems~~ support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme (RAS) where the ~~Special Protection System or Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner~~Interchange Coordinator or Interchange Authority~~

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. ~~Each Special Protection System or Remedial Action Scheme~~ Each RAS where the ~~Special Protection System or Remedial Action Scheme~~RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-~~5.1a~~Y8:

4.2.3.1. Cyber Systems~~Assets~~ at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Systems~~Assets~~ associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESP).

4.2.3.3. Cyber Systems, associated with communication networks and data communication links, between the Cyber Systems providing confidentiality and integrity of an ESP that extends to one or more geographic locations.

~~4.2.3.3.~~4.2.3.4. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

~~4.2.3.4.~~4.2.3.5. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. **Effective Dates:** See ~~"Project 2021-03 CIP-002~~ Implementation Plan for CIP-002~~"~~

~~1. **24 Months Minimum** – CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~6. **Background:**~~

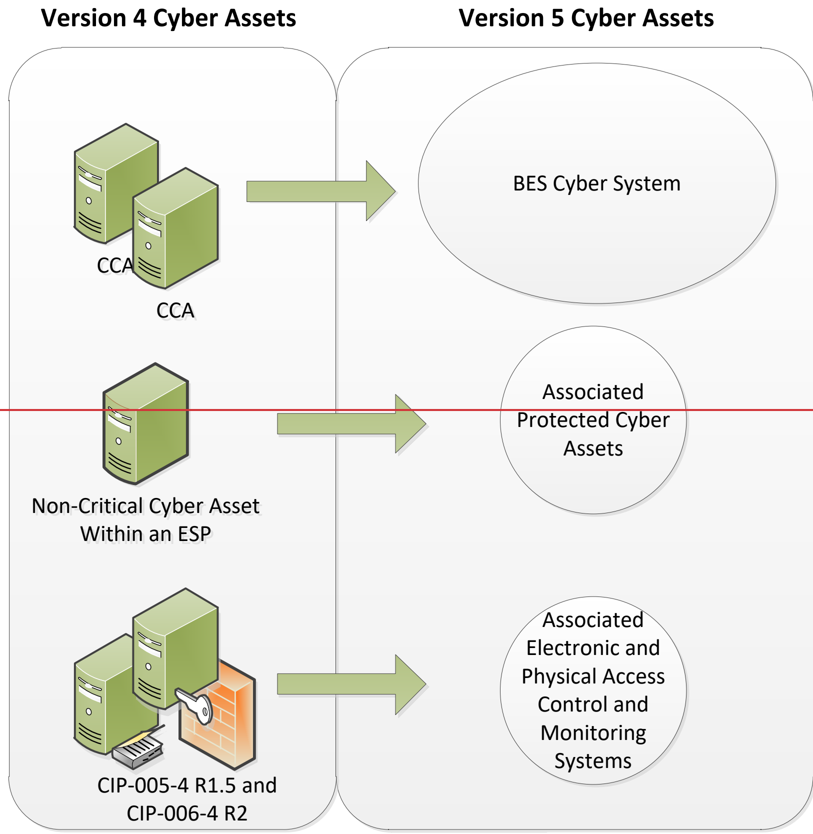
~~This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.~~

~~Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."~~

~~Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~**BES Cyber Systems**~~

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

~~Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.~~

~~It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too~~

~~tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~Reliable Operation of the BES~~

~~The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.~~

~~Real-time Operations~~

~~One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.~~

~~Categorization Criteria~~

~~The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.~~

~~This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.~~

~~**Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems**~~

~~BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:~~

~~**Electronic Access Control or Monitoring Systems ("EACMS")** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.~~

~~**Physical Access Control Systems ("PACS")**– Examples include: authentication servers, card systems, and badge control systems.~~

~~**Protected Cyber Assets ("PCA")** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.~~

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of ~~p~~Parts 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** ~~Special Protection Systems~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BCS~~BES Cyber Systems~~ according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BCS~~BES Cyber Systems~~ according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BCS~~BES Cyber System~~ according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1~~, and Parts 1.1 and 1.2~~.

R2. Each~~The~~ Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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. ~~The Regional Entity shall serve as the Compliance Enforcement Authority ("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

1.2. Evidence Retention:

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

The 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 Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and ~~Assessment Processes~~Enforcement Program:

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

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

~~**1.4. Additional Compliance Information**~~

- ~~None~~

~~Table of Compliance Elements~~

Violation Severity Levels

R #	Violation Severity Levels (CIP-002-~~5.1a~~Y8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets,- 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, five percent or fewer of identified BCS~~BES~~	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber~~	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than 15 percent of identified BCS~~BES Cyber Systems~~ have

R #	Violation Severity Levels (CIP-002-~~5.1aY~~8)			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	~~Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, five or fewer identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, five percent or fewer high or medium BCS~~BES Cyber Systems~~ have not been identified;	~~Systems~~, more than five percent but less than or equal to 10 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact and BCS~~BES Cyber Systems~~, more than five but less than or equal to 10 identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than five	100 high or medium impact BCS~~BES Cyber Systems~~, more than 10 percent but less than or equal to 15 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact and BCS~~BES Cyber AssetsSystems~~, more than 10 but less than or equal to 15 identified BCS~~BES Cyber AssetsSystems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of	not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than 15 identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than 15 percent of high or medium impact BCS~~BES Cyber Systems~~ have not been identified;

R #	Violation Severity Levels (CIP-002-~~5.1a~~Y8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, five or fewer high or medium BCS~~BES Cyber Systems~~ have not been identified.	percent but less than or equal to 10 percent high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than five but less than or equal to 10- high or medium BCS~~BES Cyber Systems~~ have not been identified.	100 high and medium impact BCS~~BES Cyber Systems~~, more than 10 percent but less than or equal to 15 percent high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than 10 but less than or equal to 15- high or medium BCS~~BES Cyber Systems~~ have not been identified.	OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than 15 high or medium impact BCS~~BES Cyber Systems~~ have not been identified.
R2	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 15 calendar months but less than or equal to 16 calendar months of the	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 16 calendar months but less than or equal to 17 calendar months of the	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 17 calendar months but less than or equal to 18 calendar months of the	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 18 calendar months of the previous review. (Part 2~~R2~~.1)

R #	Violation Severity Levels (CIP-002-~~5.1a~~Y8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	previous review. (Part 2~~R2~~.1) OR The Responsible Entity did not complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (Part 2~~R2~~.2)	previous review. (Part 2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (Part 2~~R2~~.2)	previous review. (Part 2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (Part 2~~R2~~.2)	OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (Part 2~~R2~~.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

~~None.~~

- Implementation Plan for Project 2021-03
- CIP-002-8 Technical Rationale

~~CIP-002-5.1a –~~ Attachment 1 – Impact Rating Criteria

~~**Impact Rating Criteria**~~

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High impact rating~~Impact Rating (H)~~

Each BCS~~BES Cyber System~~ used by and located at any of the following:

1.1. For Reliability Coordinators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks ~~functional obligations~~ of the ~~operated by a~~ Reliability Coordinator.

1.2. For Balancing Authorities, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the ~~operated by a~~ Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center ~~used to perform the functional obligations of the operated by a Transmission Operator or owned by a Transmission Owner,~~ for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 For Generator Operators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the ~~operated by a~~ Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium impact rating~~Impact Rating (M)~~

Each BCS~~BES Cyber System~~, not included in Section 1 above, associated with any of the ~~equipment as described in~~ following ~~criteria 2.1 through 2.10~~:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BCS~~BES Cyber Systems~~ that meet this criterion are ~~those~~each discrete shared BCS~~BES Cyber Systems~~ that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BCS~~BES~~

~~Cyber Systems~~ that meet this criterion are ~~those~~each discrete shared BCS~~BES Cyber Systems~~ that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each ~~Special Protection System (SPS), Remedial Action Scheme (~~RAS~~),~~ or automated switching System that operates BES Elements, that, if destroyed, degraded, misused or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

~~Each BES Cyber System, not included in Section 1 above, used by and located at any of the Control Centers or backup Control Centers described in criteria 2.11 through 2.13~~:

~~**2.10.**~~**2.11.** For Generator Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center~~, not already included in High Impact Rating (H) above,~~ used to perform the reliability tasks~~functional obligations~~ of the ~~operated by a~~ Generator Operator for an ~~where the~~ aggregate highest rated net Real Power capability of~~in~~ the preceding 12 calendar months equal~~s~~ to or exceeding 1500 MW in a single Interconnection.

2.12. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center with an "aggregate weighted value' exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per BES Transmission Line" that is monitored and controlled by the Control Center or backup Control Center shown in the table below. Include each BES Transmission Line that is connected between two or more Transmission stations or substations. ~~used to perform the functional obligations of the , operated by a Transmission Operator or owned by a Transmission Owner, not included in High Impact Rating (H), above. with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per BES Transmission Line" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.~~

Voltage Value of a BES Transmission Line	**Weight Value per BES Transmission Line**
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:

Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may ~~calculate a modified "aggregate weighted value" that~~ excludes the BES Transmission Lines that are contained in a single group of contiguous Elements from their "aggregate weighted value" calculation, where a group of contiguous Elements is defined as:~~monitored and controlled by the Control Center or backup Control Center that are part of a single group of contiguous transmission Elements that operate at less than 300kV, and where the gross export does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The gross export is based on the hourly integrated values for the most recent 12-month period.~~

- a group of contiguous Elements emanating from multiple points of connection at 69kV or higher;
- that are operated at less than 300kV; and
- where the gross export does not exceed 75 MW during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

~~2.11.~~2.13. For Balancing Authorities, e~~E~~ach Control Center or backup Control Center~~, not already included in High Impact Rating (H) above,~~ used to perform the reliability tasks~~functional obligations~~ of the ~~operated by a~~ Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low impact rating~~Impact Rating (L)~~

BCS~~BES Cyber Systems~~ not included in Sections 1 or 2 above that are ~~used by and located at~~ associated with any of the ~~Control Centers or backup Control Centers described in criteria 3.1~~following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

~~BES Cyber Systems not included in Sections 1 or 2 above that are associated with any equipment as described in criteria 3.2 through 3.6:~~

~~3.1.~~3.2. Transmission stations and substations.

~~3.2.~~3.3. Generation resources.

~~3.3.~~3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

~~3.4.~~3.5. ~~Special Protection Systems~~RAS that support the reliable operation of the ~~Bulk Electric System~~BES.

~~3.5.~~3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

~~Guidelines and Technical Basis~~ (Project 2021-03 decided to highlight the title versus the entire section of the GTB. The GTB sections were removed by Project 2016-02.)

~~Section 4 – Scope of Applicability of the CIP Cyber Security Standards~~

~~Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.~~

~~Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.~~

~~Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.~~

~~For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.~~

~~CIP-002-5.1a~~

~~CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."~~

~~The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber Systems that would be subject to CIP-002-5.1a. The concept includes a number of named BES reliability operating services. These named services include:~~

~~Dynamic Response to BES conditions~~
~~Balancing Load and Generation~~
~~Controlling Frequency (Real Power)~~
~~Controlling Voltage (Reactive Power)~~
~~Managing Constraints~~
~~Monitoring & Control~~
~~Restoration of BES~~
~~Situational Awareness~~
~~Inter-Entity Real-Time Coordination and Communication~~

~~Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.~~

~~Entity Registration~~	~~RC~~	~~BA~~	~~TOP~~	~~TO~~	~~DP~~	~~GOP~~	~~GO~~
~~Dynamic Response~~		~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Balancing Load & Generation~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Controlling Frequency~~		~~X~~				~~X~~	~~X~~
~~Controlling Voltage~~			~~X~~	~~X~~	~~X~~		~~X~~
~~Managing Constraints~~	~~X~~		~~X~~			~~X~~	
~~Monitoring and Control~~			~~X~~			~~X~~	
~~Restoration~~			~~X~~			~~X~~	
~~Situation Awareness~~	~~X~~	~~X~~	~~X~~			~~X~~	
~~Inter-Entity coordination~~	~~X~~	~~X~~	~~X~~	~~X~~		~~X~~	~~X~~

~~Dynamic Response~~

~~The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These~~

~~actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:~~

- ~~Spinning reserves (contingency reserves)~~
  - ~~Providing actual reserve generation when called upon (GO,GOP)~~
  - ~~Monitoring that reserves are sufficient (BA)~~
- ~~Governor Response~~
  - ~~Control system used to actuate governor response (GO)~~
- ~~Protection Systems (transmission & generation)~~
  - ~~Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)~~
  - ~~Zone protection for breaker failure (DP, TO, TOP)~~
  - ~~Breaker protection (DP, TO, TOP)~~
  - ~~Current, frequency, speed, phase (TO,TOP, GO,GOP)~~
- ~~Special Protection Systems or Remedial Action Schemes~~
  - ~~Sensors, relays, and breakers, possibly software (DP, TO, TOP)~~
- ~~Under and Over Frequency relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Under and Over Voltage relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Power System Stabilizers (GO)~~

~~Balancing Load and Generation~~

~~The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:~~

- ~~Calculation of Area Control Error (ACE)~~
  - ~~Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)~~
  - ~~Software used to perform calculation (BA)~~
- ~~Demand Response~~
  - ~~Ability to identify load change need (BA)~~

- ~~Ability to implement load changes (TOP,DP)~~

- ~~Manually Initiated Load shedding~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP, DP)~~
- ~~Non-spinning reserve (contingency reserve)~~
  - ~~Know generation status, capability, ramp rate, start time (GO, BA)~~
  - ~~Start units and provide energy (GOP)~~

~~Controlling Frequency (Real Power)~~

~~The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:~~

- ~~Generation Control (such as AGC)~~
  - ~~ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)~~
  - ~~Software to calculate unit adjustments (BA)~~
  - ~~Transmit adjustments to individual units (GOP)~~
  - ~~Unit controls implementing adjustments (GOP)~~
- ~~Regulation (regulating reserves)~~
  - ~~Frequency source, schedule (BA)~~
  - ~~Governor control system (GO)~~

~~Controlling Voltage (Reactive Power)~~

~~The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:~~

- ~~Automatic Voltage Regulation (AVR)~~
  - ~~Sensors, stator control system, feedback (GO)~~
- ~~Capacitive resources~~
  - ~~Status, control (manual or auto), feedback (TOP, TO,DP)~~
- ~~Inductive resources (transformer tap changer, or inductors)~~
  - ~~Status, control (manual or auto), feedback (TOP,TO,DP)~~

- ~~Static VAR Compensators (SVC)~~
  - ~~Status, computations, control (manual or auto), feedback (TOP, TO,DP)~~

~~Managing Constraints~~

~~Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:~~

- ~~Available Transfer Capability (ATC) (TOP)~~
- ~~Interchange schedules (TOP, RC)~~
- ~~Generation re-dispatch and unit commit (GOP)~~
- ~~Identify and monitor SOL's & IROL's (TOP, RC)~~
- ~~Identify and monitor Flow gates (TOP, RC)~~

~~Monitoring and Control~~

~~Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:~~

- ~~All methods of operating breakers and switches~~
  - ~~SCADA (TOP, GOP)~~
  - ~~Substation automation (TOP)~~

~~Restoration of BES~~

~~The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:~~

- ~~Restoration including planned cranking path~~
  - ~~Through black start units (TOP, GOP)~~
  - ~~Through tie lines (TOP, GOP)~~
- ~~Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)~~
- ~~Coordination (TOP, TO, BA, RC, DP, GO, GOP)~~

~~Situational Awareness~~

~~The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:~~

- ~~Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)~~
- ~~Change management (TOP,GOP,RC,BA)~~
- ~~Current Day and Next Day planning (TOP)~~
- ~~Contingency Analysis (RC)~~
- ~~Frequency monitoring (BA, RC)~~

~~Inter-Entity Coordination~~

~~The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:~~

- ~~Scheduled interchange (BA,TOP,GOP,RC)~~
- ~~Facility operational data and status (TO, TOP, GO, GOP, RC, BA)~~
- ~~Operational directives (TOP, RC, BA)~~

~~Applicability to Distribution Providers~~

~~It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.~~

~~Requirement R1:~~

~~Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.~~

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

~~**Attachment 1**~~

~~**Overall Application**~~

~~In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.~~

- ~~When the drafting team uses the term "Facilities", there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)." In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.~~
- ~~In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.~~
- ~~It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.~~

~~**High Impact Rating (H)**~~

~~This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the~~

~~functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.~~

~~The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.~~

~~Additional thresholds as specified in the criteria apply for this category.~~

~~Medium Impact Rating (M)~~

~~Generation~~

~~The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.~~

- ~~Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.~~

~~In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.~~

~~By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.~~

~~The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.~~

- ~~In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.~~

  ~~If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.~~

  ~~The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.~~

- ~~Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2,~~ ~~**Establish and Communicate System Operating Limits**~~~~, R5.1.1 and R5.1.3.~~

  ~~IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.~~

- ~~Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.~~

- ~~Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.~~

- ~~Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~**Transmission**~~

~~*The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.*~~

- ~~Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems~~

~~for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.~~

- ~~Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.~~

  ~~It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.~~

- ~~Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:~~

  - ~~Excluded radial facilities that would only provide support for single generation facilities.~~
  - ~~Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.~~

  ~~The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.~~

  ~~Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:~~

  - ~~230 kV –> 700 MVA~~
  - ~~345 kV –> 1,300 MVA~~
  - ~~500 kV –> 2,000 MVA~~

- ~~765 kV –> 3,000 MVA~~

~~In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:~~

- ~~For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.~~

- ~~Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.~~

- ~~Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.~~

~~Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.~~

1. ~~The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations. This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.~~
2. ~~The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV~~

~~or higher in the table of values for the contribution to the aggregate value of 3000.~~

~~The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.~~

- ~~Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.~~
- ~~Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.~~
- ~~Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.~~
- ~~Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.~~
- ~~Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest~~

~~MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.~~

~~This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~In ERCOT, the Load acting as a Resource (“LaaR”) Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.~~

~~The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.~~

- ~~Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.~~
- ~~Criterion 2.13 categorizes as Medium Impact those BA Control Centers that “control” 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~Low Impact Rating (L)~~

~~BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.~~

~~Restoration Facilities~~

- ~~Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.~~

  ~~In response, the CIP Version 5 drafting team sought informal input from NERC’s Operating and Planning Committees. The committees indicate there has already been a reduction in Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.~~

~~The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.~~

~~Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.~~

~~BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.~~

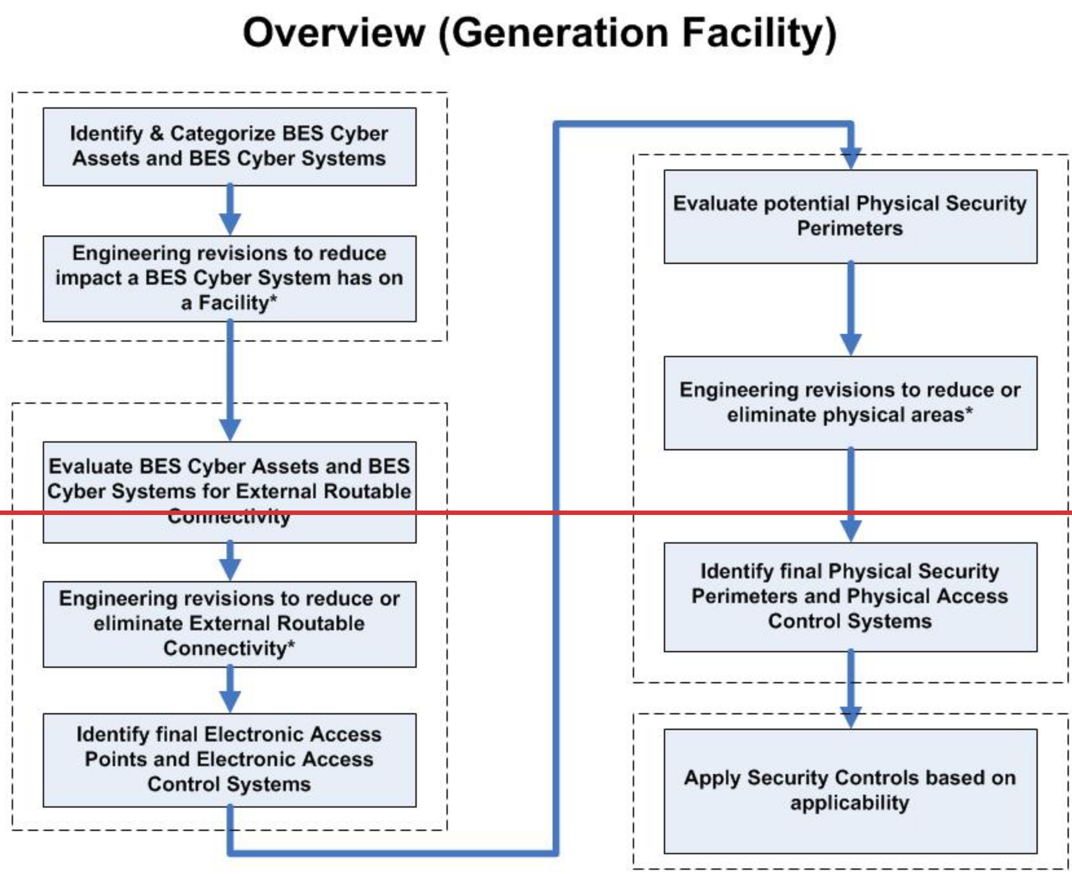
~~Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."~~

- ~~BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.~~

~~Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.~~

~~Use Case: CIP Process Flow~~

~~The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.~~



* - Engineering revisions will need to be reviewed for cost justification, operational\safety requirements, support requirements, and technical limitations.

~~Rationale:~~

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

~~Rationale for R1:~~

~~BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of "bright-line" criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.~~

~~Rationale for R2:~~

~~The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager's approval ensures proper oversight of the process by the appropriate Responsible Entity personn~~

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity.	

		Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board of Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced “Devices” with “Systems” in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
~~Y8~~	TBD	Transmission Owners Control Centers Update	

~~Appendix 1~~

~~Requirement Number and Text of Requirement~~
~~CIP-002-5.1, Requirement R1~~ ~~R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:~~ ~~i. Control Centers and backup Control Centers;~~ ~~ii. Transmission stations and substations;~~ ~~iii. Generation resources;~~ ~~iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;~~ ~~v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and~~ ~~vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.~~ ~~1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;~~ ~~1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and~~ ~~1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).~~ ~~Attachment 1, Criterion 2.1~~ ~~2. Medium Impact Rating (M)~~ ~~Each BES Cyber System, not included in Section 1 above, associated with any of the following:~~ ~~2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.~~

~~**Questions**~~
~~Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."~~ ~~The Interpretation Drafting Team identified the following questions in the RFI:~~ ~~1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~ ~~2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~ ~~3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~
~~**Responses**~~
~~**Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?**~~ ~~The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)~~ ~~Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:~~ ~~The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~**Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?**~~

~~The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.~~

~~The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:~~

> ~~Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1:~~ ~~**Impact Rating of Generation Resource Shared BES Cyber Systems**~~ ~~for further information and examples.~~

~~**Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?**~~

~~The phrase applies to each discrete BES Cyber System.~~

Implementation Plan

Project 2021-03 CIP-002 | Reliability Standard CIP-002-8

Applicable Standard(s)

- Reliability Standard CIP-002-8 – Cyber Security - BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-7 – Cyber Security - BES Cyber System Categorization

Prerequisite Definition

This definition must be approved before the Applicable Standard becomes effective:

- Cyber System[1]

Applicable Entities

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

Modified 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 Modified Definition

Control Center - One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator

[1] The new term Cyber System was developed as part of Project 2016-02 – Modifications to CIP Standards.

for transmission Facilities at two or more locations, or 5) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

Background

Project 2021-03 includes revisions to the Control Center definition and CIP-002 Attachment 1. The proposed revisions to the Control Center definition are intended to ensure Transmission Owners correctly identify their Control Centers. The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers that have the capability to control transmission Facilities at two or more locations in real-time using SCADA. These modifications resulted from recommendations from the CIP-002 Transmission Owner Control Center Field Test Report.[2]

General Considerations

This Implementation Plan includes phased-in implementation dates for CIP-002-8, Attachment 1. The phased-in implementation dates allow Responsible Entities[3] a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System.

Effective Date and Phased-In Compliance Dates

The effective date for proposed Reliability Standard CIP-002-8 and the modified definition is provided below. Where the drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (i.e., an entire Requirement or a portion of it), the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible 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 CIP-002-8 and Control Center Definition

Where approval by an applicable governmental authority is required, the standard and Control Center definition shall become effective on the later of 1) the effective date of CIP-002-7; or 2) the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving CIP-002-8, or as otherwise provided for by the applicable governmental authority.

[2] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf

[3] As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

Where approval by an applicable governmental authority is not required, the standard and Control Center definition shall become effective on the later of 1) the effective date of CIP-002-7; or 2) the first day of the first calendar quarter that is three (3) months after the date CIP-002-8 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Dates for CIP-002-8

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-8, Requirement R2 within 15 calendar months of their last performance of Requirement R2 under the version of CIP-002 immediately effective prior to CIP-002-8.

Phased-in Implementation Date for CIP-002-8, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criteria 2.12 of Attachment 1 to CIP-002-8 result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as that higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP- 002-8. This would be considered a planned change, such that the Responsible Entity is expected to comply with the higher categorization 24 months after the effective date of CIP-002-8 as opposed to further extensions that would be allowable for an unplanned change. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a or CIP-002-7, Requirement R1, Part 1.3, whichever version of CIP-002 is enforceable immediately prior to the effective date of CIP-002-8.

Planned or Unplanned Changes

Planned Changes

Planned changes refer to any changes of the electric system or a BES Cyber System which were planned and implemented by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-8, Requirement R2.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-8, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

For planned changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control or Monitoring Systems and Protected Cyber Assets, etc. For periodic requirements in Reliability Standards CIP-004 through CIP-011, the period within which Responsible Entities must initially comply begins on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control or Monitoring Systems and Protected Cyber Assets.

Unplanned Changes

Unplanned changes refer to any changes of the electric system or a BES Cyber System which were not planned by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-8, Requirement R2.

For example, consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-8, Attachment 1, then an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-8, Attachment 1, criteria.

For unplanned changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control or Monitoring Systems and Protected Cyber Assets, etc. For periodic requirements in Reliability Standards CIP-004 through CIP-011, the period within which Responsible Entities must initially comply begins at the end of the timelines listed below.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to Medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System	12 months
Responsible Entity identifies its first high impact or medium impact BES Cyber System (i.e., the Responsible Entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002 identification and categorization processes)	24 months

Retirement Date

Reliability Standard CIP-002-7

Reliability Standard CIP-002-7 shall be retired immediately prior to the effective date of Reliability Standard CIP-002-8 in the particular jurisdiction in which the revised standard is becoming effective.

Unofficial Comment Form

Project 2021-03 CIP-002

Do not use this form for submitting comments. Use the [Standards Balloting and Commenting System (SBS)] to submit comments on **Project 2021-03 CIP-002** by **8 p.m. Eastern, Tuesday, October 15, 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 2021-03 currently has four assigned Standard Authorization Requests (SARs). The proposed standard revisions are based on the Project 2016-02 SAR which seeks to modify Reliability Standard CIP-002 to address the categorization of certain Transmission Owner Control Centers (TOCC) performing Transmission Operator (TOP) functions as medium impact based on an aggregate weighted value of their Bulk Electric System (BES) Transmission Lines in Criterion 2.12. The remaining three SARs will be addressed at a later date.

The Standards Committee (SC) assigned a portion of the Project 2016-02 SAR to the Project 2021-03 Drafting Team (DT) at its March 17, 2021 meeting. In addition, the DT assisted NERC staff in meeting the directive from the NERC Board of Trustees to conduct further study of the need to readdress the applicability of the Critical Infrastructure Protection (CIP) Reliability Standards to theses Control Centers to support reliability. To help meet this directive and the scope of the SAR, the DT initiated a field test. The SC approved the Project 2021-03 Field Test Plan on November 17, 2021. Three fields tests were conducted in 2022 and the final report was posted to the project page in January 2023.

Summary of Changes Overview

The DT reviewed all comments and made modifications to the Control Center definition and the Reliability Standard accordingly.

The DT identified that the changes previously proposed to the Control Center definition that were intended to address existing areas of ambiguity such as use of the term ‘associated data center’ and further defining reliability tasks performed by registered entities created additional challenges. Therefore, the DT has reverted to the original Control Center definition language as it applies to the Reliability Coordinator, Balancing Authority, TOP and Generator Operator. The DT has added a specific provision to the definition that applies to the TO to ensure registered entities properly identify TOCCs based on the capability to control transmission Facilities at two or more locations in real-time using SCADA. The DT recognizes that a SCADA system may include telemetry, so the DT has crafted language to specifically exclude field Cyber Assets used for telemetry from being part of the Control Center and associated impact level determination.

The DT decided on using the “OR” versus adding the TO as a fifth bullet in the original definition in order to clearly delineate between the capability of a TO to control transmission Facilities in real-time using Supervisory Control and Data Acquisition (SCADA) and the concept of hosting operating personnel who monitor and control the BES in real-time to perform reliability tasks. This is to ensure that TOs do not inappropriately assume that they do not have operating personnel or perform reliability tasks.

In addition to the changes to the Control Center definition, the DT has proposed changes to CIP-002-8 Attachment 1. The DT has proposed to replace the term 'functional obligations' with the term 'reliability tasks'. This is viewed as an improvement over use of 'functional obligations' as it eliminates the obsolete reference to the NERC Functional Model. It also aligns CIP-002 language with the existing language of the Control Center definition and is viewed as a net neutral change that will not further complicate the challenges surrounding aggregation of BES versus non-BES resources for calculating net Real Power. The DT has also reworded the exclusion clause to clarify and simplify the concept. Further, the team replaced the concept of a group of contiguous transmission Elements (GCTE) with the concept of a group of contiguous Elements to clarify that the group of Elements may contain transmission Elements and non-transmission Elements. For a detailed explanation of these changes, please refer to the *CIP-002-8 Technical Rationale*.

Based on recent board adopted standard CIP-002-7, the posted version for 2021-03 CIP-002 reflects CIP-002-8. The SBS does not allow edits once a ballot is created and/or opened. Even though the standard versioning within the SBS states CIP-002-Y, the version number within this posting is correct and entities will be voting on CIP-002-8.

The CIP-002-7 redlines have been incorporated into CIP-002-8. Per the CIP-002-8 Implementation Plan, the standard and Control Center definition will become effective on the later of 1) the effective date of CIP-002-7 or 2) the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving CIP-002-8, or as otherwise provided for by the applicable governmental authority.

Where approval by an applicable governmental authority is not required, the standard and Control Center definition shall become effective on the later of 1) the effective date of CIP-002-7; or 2) the first day of the first calendar quarter that is three (3) months after the date CIP-002-8 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

In addition, the proposed revised definition is being balloted via the standard. As such, when voting, ballot body participants will also be voting on the proposed, revised definition used in the standard.

Questions

1. Based on industry comments from informal and formal outreach, the DT has modified the Control Center definition. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and a recommendation for an alternate definition.

   ☐ Yes
   ☐ No

   Comments:

2. Language throughout Attachment 1 of CIP-002-8 that referred to the “functional obligations” of the different Registered Entities has been replaced with the term “reliability tasks”. This change was incorporated given that the NERC Functional Model is no longer being actively maintained and aligns with CIP-002 language with the existing language of the Control Center definition. Do you agree with the proposed changes to CIP-002-8? Does the change introduce reliability gaps to the Registered Entities? If not, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

3. The DT reworded the exclusion clause in Criteria 2.12 to provide clarity and to simplify the concepts. Further, the DT replaced the concept of a group of contiguous transmission Elements (GCTE) with the concept of a group of contiguous Elements to clarify that the group of Elements may contain transmission Elements and non-transmission Elements. Lastly, the 75 MW gross export limitation was changed to 75 MWh to appropriately reflect an hourly integrated gross export, as opposed to an instantaneous measurement within the hour. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

4. For the Implementation Plan, the DT elected to retain 24-month window as it aligns with the established 24-month window that is currently provided to Responsible Entities who identify their first high impact or medium impact BES Cyber System. Further, given that the earliest effective date of CIP-002-8 is April 1, 2026 (aligning with the earliest possible effective date of CIP-002-7), entities will have adequate time to evaluate impacts before the 24-month window commences. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

   ☐ Yes
   ☐ No

   Comments:

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

   Comments:

Technical Rationale

Project 2021-03 CIP-002 | Reliability Standard CIP-002-8

CIP-002-8 – Cyber Security – BES Cyber System Categorization and Control Center Definition

Introduction

This document explains the technical rationale and justification for the proposed revisions to the Control Center Definition and Reliability Standard CIP-002-8. It provides stakeholders and the ERO Enterprise with a description of the technical requirements in the Reliability Standard. These are not Reliability Standards and should not be considered mandatory and enforceable.

Updates to this document include the Project 2021-03 CIP-002 Drafting Team's (DT's) intent in drafting changes to the requirements and definition.

Overview

Project 2021-03 proposes revisions to the Control Center definition and CIP-002-8 criterion 2.12 in Attachment 1. CIP-002-8 provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems (BCS) based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System (BES). The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers (TOCCs) performing the functional obligations of a Transmission Operator (TOP), specifically those that meet medium impact criteria, and clarifying the language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.

Rationale for Control Center Definition Modification

Rationale for Proposing Modifications to the Control Center Definition

During the CIP-002 TOCC Field Test[1], it was found that many Transmission Owners (TO)s struggled with how to interpret the Control Center definition. While the current Control Center definition does not specifically identify TOs, a TO may have a Control Center through its ability to monitor and control the BES in real-time to perform the reliability tasks of a TOP. This struggle surfaced in the following three manners:

- Lack of a common understanding of the term "control" versus "authority" as it relates to TOPs
- Lack of a common understanding of the term "perform the functional obligations of the TOP" as stated in Attachment 1 of CIP-002-5.1a.
- Lack of a common understanding of the term "associated data centers" versus TO BES Cyber Assets capable of controlling transmission Facilities.

Modifications to the definition have been proposed to eliminate ambiguity.

[1] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

Applicable Control Center Entities

Considering industry comments, the Control Center definition for Reliability Coordinator (RC), Balancing Authority (BA), TOP, and Generator Operator (GOP) was not revised. The industry felt the Control Center and data center definitions for these registered entities were well understood and is structured to explicitly identify the four different types of registered entities have gone through the scrutiny of compliance monitoring. Thus, no changes were made for these four registered entities that could have a Control Center.

The Control Center definition was expanded to incorporate the TO as follows: One or more facilities of a TO that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers and excluding field Cyber Assets used for telemetry.

A TO is considered to have a Control Center if it has the capability to control transmission Facilities at two or more locations using SCADA. The concept of ‘capability to control using SCADA’ is specifically used to clarify that a facility used by a TO that monitors Facilities without any capability to electronically control those Facilities using a SCADA system does not fall within the Control Center definition. For example, a TO who issues verbal instructions to field switching personnel, but who does not have the ‘capability to control using SCADA’ would not be considered to have a Control Center. As another example, a tool that is used by engineers to access relay settings installed in the field would not fall under consideration as a Control Center, as it does not provide the ‘capability to control using SCADA.’ The tool would need to be evaluated against Attachment 1 criteria to determine the appropriate impact rating level at which the BES Cyber Assets associated with the tool should be protected.

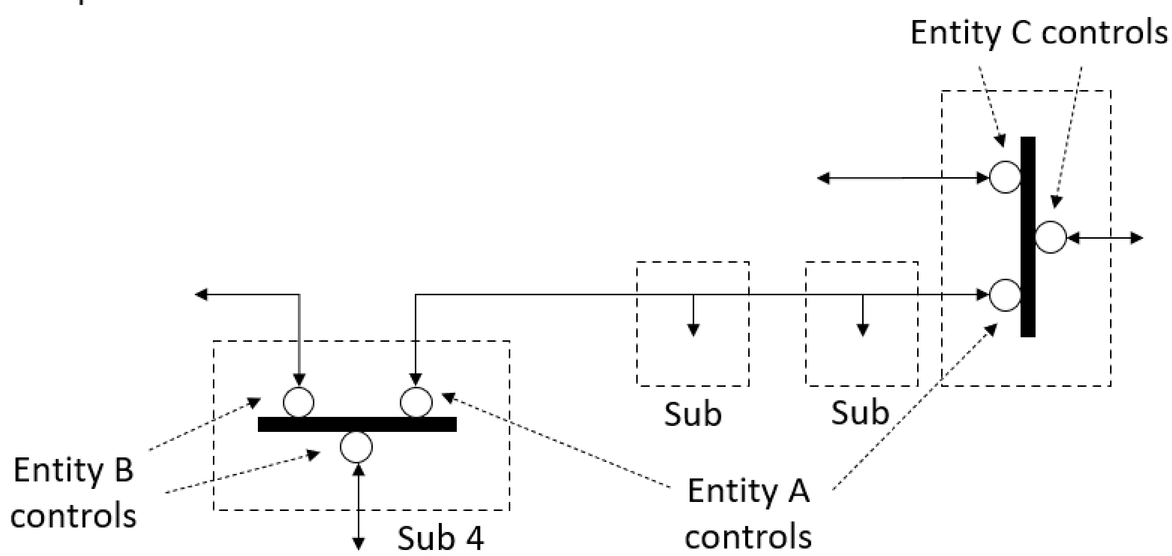
Since the SCADA system may include telemetry, the DT has crafted language to specifically exclude field Cyber Assets used for telemetry from being part of the Control Center and associated impact level determination. The impact level of field Cyber Assets, including telemetry, should be evaluated based on the location and associated impact level contained in Attachment 1.

The part of the Control Center definition that is applicable to the TO is not tied to the functional obligations of the TOP, nor is it tied to any TOP reliability tasks. Rather, it is tied to having a BES Cyber Asset, i.e., a SCADA system with the capability to control. It does not matter if the TO has a reliability task with pre-authorized authority from the TOP to control transmission Facilities or only receives operating instructions from the TOP. The cyber security risk that must be protected is access to the BES Cyber Asset, i.e., SCADA system that can control the transmission Facility.

When considering the language “transmission Facilities at two or more locations” and “generation Facilities at two or more locations,” it is generally expected that the Facilities will have separate street addresses. Facilities located at a single street address would be associated with a single location. An entity must have more than one Facility and must have Facilities at two or more locations in order to have “transmission Facilities at two or more locations” or “generation Facilities at two or more locations.”

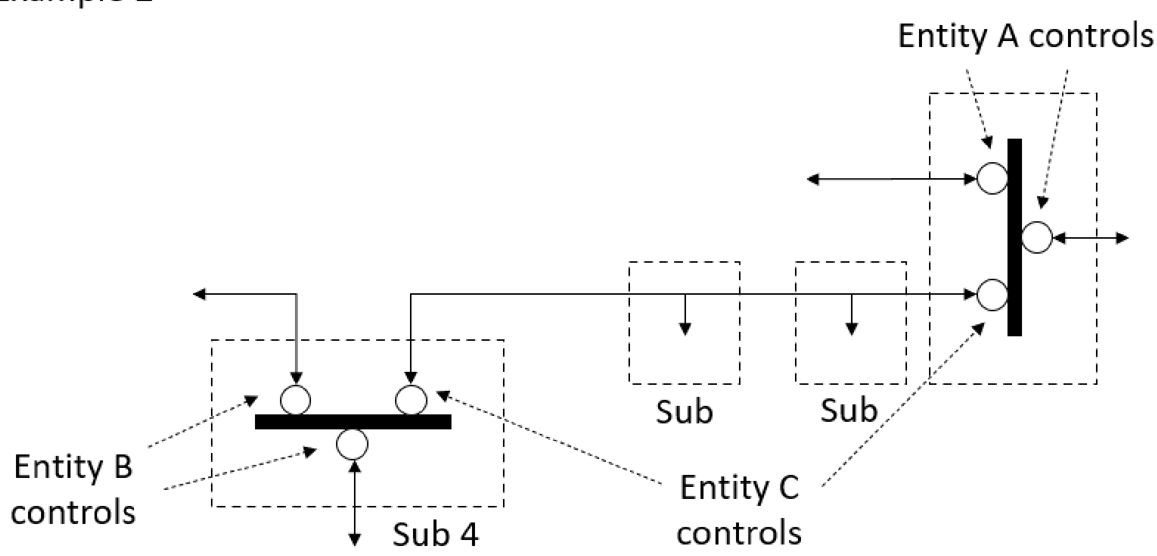
The following examples differentiate between a single transmission Facility and two or more transmission Facilities at one location.

Example 1



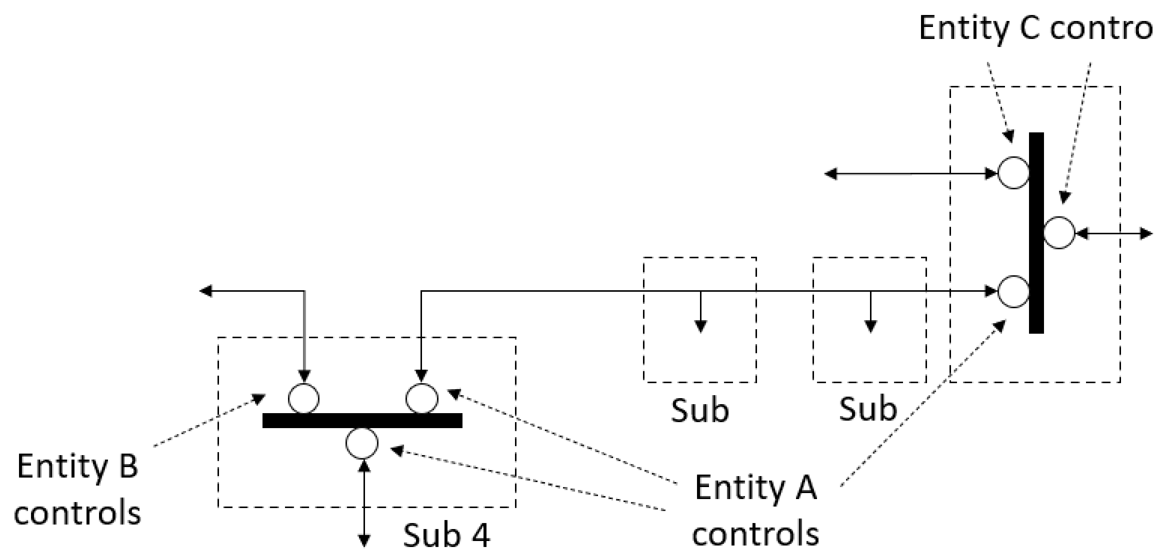
In Example 1, Entity A has control of breakers at both ends of a Transmission Line, which constitutes a transmission Facility. Because Entity A controls a single transmission Facility at 2 locations, Entity A does not meet the TO or TOP Control Center definition.

Example 2



In Example 2, Entity A has control of breakers at one end of two transmission Facilities, but at a single location. Because Entity A controls two transmission Facilities at only 1 location, Entity A does not meet the TO or TOP Control Center definition.

Example 3



In Example 3, Entity A has control of breakers at one end of two transmission Facilities and a breaker at different location. Because Entity A controls two transmission Facilities at 2 locations, Entity A does meet the TO or TOP Control Center definition.

Associated Data Centers

The Control Center definition includes the phrase “associated data centers”. This phrasing is intended to ensure that Cyber Assets that are not co-located in the facilities that host operating personnel are included in the Control Center definition, and are thus included in the process of identifying and categorizing BCS.

Industry comments received during the standard drafting process indicate that lack of a NERC definition for data center has not been an issue in applying the Control Center definition. Therefore, the term “associated data center” was retained in the revised definition.

Rationale for CIP-002-8 Attachment 1 Modifications

Removal of Functional Obligation Language

Language throughout Attachment 1 of CIP-002-8 that referred to the “functional obligations” of the different Registered Entities has been replaced with references to the reliability tasks performed by those same Registered Entities. This change was incorporated given that the NERC Functional Model is no longer being actively maintained and to align with the language used in the Control Center definition. It also resolves an issue whereby an entity may be identified as performing functional obligations even though that entity is not currently registered with NERC. The proposed modifications ensure that the responsibility for entity registration precedes enforcement of CIP-002-8.

Calculating an Aggregate Weighted Value per Criteria 2.12

The total aggregate weighted value is used to account for the impact on the BES. The 6,000 aggregate weighted value threshold defined in criterion 2.12 provides sufficient differentiation for medium and low impact BCS associated with Control Centers that are operated by a registered TOP or owned by a registered TO. DT analysis of data obtained from the CIP-002 Transmission Owner Control Center Field Test[2] validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

The total aggregate weighted value of 6,000 was derived based on an entity with no single station or substation that meets criterion 2.5, but who has the capability or authority to control BES Transmission Lines with the equivalent weight of two stations or substations whose BCS would be classified as medium impact per criterion 2.5. This is ultimately derived from the “two or more locations” criteria that is documented in the Control Center definition.

For consistency with the existing Attachment 1 criteria, the weighted values for the various voltage classes of BES Transmission Lines were selected to align with the existing approved values in criterion 2.5. For BES Transmission Lines 200 kV to 299 kV and for BES Transmission Lines 300 kV to 499 kV, the weighted values per line are 700 and 1300, respectively. Similar average MVA line loadings based on kV rating were calculated for BES Transmission Lines less than 100 kV and for BES Transmission Lines 100 kV to 199 kV using Appendix A of NERC’s Severity Risk Index Enhancements Report which result in weighted values of 100 and 250, respectively.

BES Transmission Lines that are energized at voltages of 500 kV and above have no contribution to the aggregated weighted value given that criterion 2.4 already includes BCS for any transmission Facilities at substations that are operated at 500 kV or higher as medium impact. Further, criterion 1.3 includes the BCS used by and located at Control Centers or backup Control Centers that monitor and control any BES Transmission Lines at substations that are operated at 500 kV or higher as high impact. During industry commenting periods, the drafting team received many inquiries into the use of zero (0) in the table for criterion 2.12, which was originally proposed to remain consistent with existing criteria 2.5. Pursuant to these comments, the DT elected to use “0 (N/A)” in both criterion 2.5 and criterion 2.12 to make it clear that these lines are not relevant for inclusion in the aggregate weighted value calculation.

For the purpose of identifying a Responsible Entity’s BES Transmission Lines, a Transmission Line is typically defined by the Protection System(s) that would be used to isolate faults on the Transmission Line – which is generally defined by a boundary of fault interrupting devices (e.g., breakers) that are controlled by the line’s Protection System(s). Transmission Lines can be single-ended, two-ended or three-ended.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages less than 100 kV, are monitored and controlled by a Control Center, and have been specifically designated as part of the BES via the NERC Rules of Procedure (ROP) Exception Process.
- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV, connect to another Transmission station or substation, and are monitored and controlled by a Control Center. This includes BES Transmission Lines that connect to neighboring entities.

[2] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

- Multiple-point BES Transmission Lines (e.g., two-ended or three-ended lines) are considered to contribute a single weight value per line. For any fault on the line, all line breakers located at the terminals are expected to operate to clear the fault. For example, a single 230 kV three-ended line would contribute an aggregate weighted value of 700 based on the criterion 2.12 table.

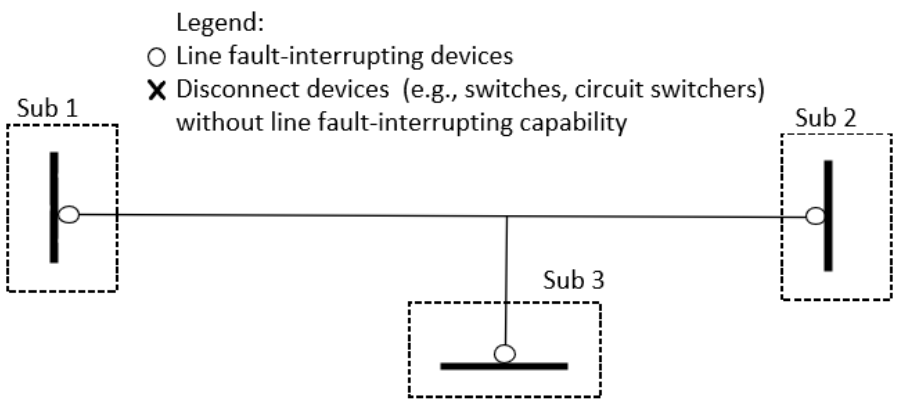


Figure 1: A 230 kV three-terminal Transmission Line contributes an aggregate weighted value of 700

- Multiple-taps BES Transmission Lines (including various implementations such as loop-in-loop-out) are considered to contribute a single weight value per line. For example, a two-ended 230 kV line with two substations tapped on the line where the substations do not have any 230 kV line fault-interrupting devices would contribute an aggregate weighted value of 700 based on the criterion 2.12 table.

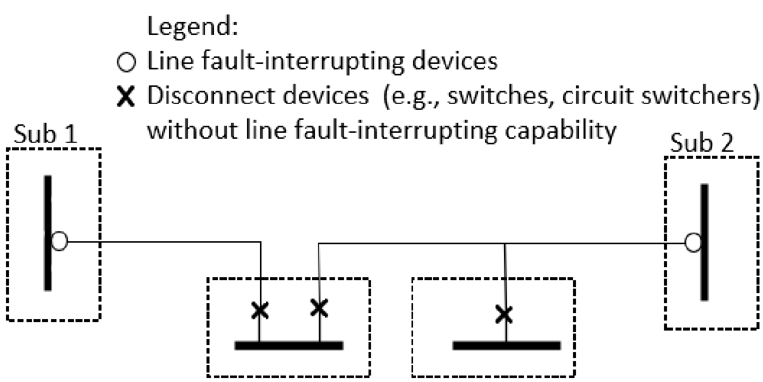


Figure 2: A 230 kV two-terminal Transmission Line with two tapped substations contributes an aggregate weighted value of 700

- Multiple lines between two transmission stations or substations are considered to contribute multiple weight values per line. For example, two two-ended 345 kV lines that connect between the same two transmission stations or substations would contribute an aggregate weighted value of 2,600 based on the criterion 2.12 table.

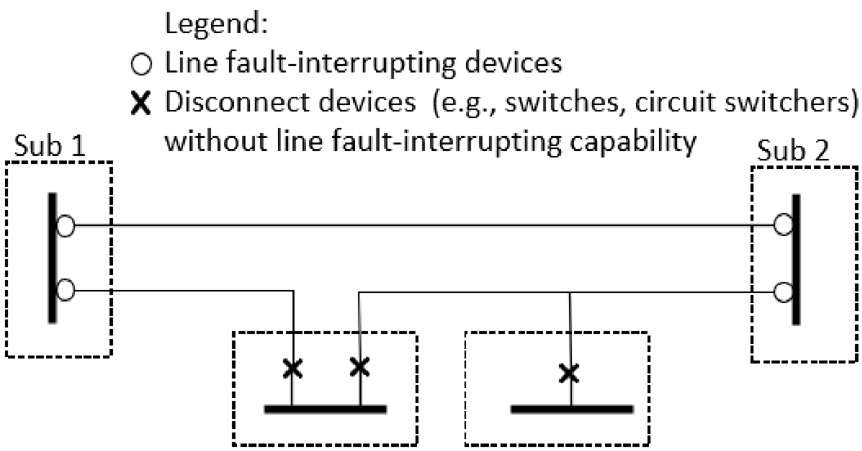


Figure 3: Two 345 kV two-terminal Transmission Lines that connect between the same two Transmission stations or substations contribute an aggregate weighted value of 2,600

Applying the Exclusion Clause per Criterion 2.12

An exclusion clause has been provided to allow Responsible Entities to appropriately categorize their BES Cyber Assets at Control Centers at a level that is commensurate with the associated risk for local systems having limited flow-through or generation export, and are primarily designed to serve load.

The exclusion clause applies to TOPs and TOs where the initial calculated aggregated weighted value (AWV) is less than 12,000. In such cases, the TOP/TO may calculate a revised AWV that excludes those BES Transmission Lines that are contained in a single group of contiguous Elements (GCE[3]) operated at or greater than 69 kV but less than 300 kV, as defined by the Responsible Entity. The hourly integrated gross export from the GCE must not exceed 75 MWh during the preceding 12 calendar months during non-Energy Emergency Alert (EEA) conditions. Gross exports from the GCE during an EEA condition that exceed 75 MWh are allowed to enable the Responsible Entity to provide support to neighboring entities during EEA conditions without any compliance impact.

Entities that choose to pursue an exclusion under criterion 2.12 are responsible for documenting the process whereby they will calculate the hourly integrated gross export from the defined GCE. The concept of an hourly integrated value was selected to avoid requiring entities to use an instantaneous value. There is no requirement that entities install meters specifically for the purpose of calculating the hourly integrated gross export; however, they may do so if they choose. Alternatively, entities may choose to use SCADA data for the purposes of calculating the hourly integrated value.
An entity is responsible to clearly define the GCE and to monitor flows across the interfacing equipment in order to demonstrate compliance with CIP-002. Interfacing equipment is not limited to BES

[3] The concept of a "group of contiguous Elements" will be referred to as a GCE throughout the remainder of this document for simplicity. The acronym is solely used in this document and is not included as a defined term in the NERC Glossary of Terms.

Transmission Lines, provided that the entity is able to collect the necessary data to demonstrate gross

export from the GCE remains below 75 MWh. The GCE may contain Elements that the Control Center is not able to control, provided that the GCE boundary encompasses a transmission network that is primarily designed to serve load. The GCE specifically excludes Transmission Lines 300kV and above, as they are generally intended for the bulk transfer of power and not for local load serving purposes. A restriction to allow the responsible entity to define only one GCE is established to prohibit the ability of the entity to segment off multiple areas within a larger geographic area.

An initial calculated AWV of 12,000 is established to avoid application of the exclusion to large control areas. The AWV of 12,000 corresponds to an entity with no single station or substation that meets criterion 2.5, but who has the capability or authority to control BES Transmission Lines with the equivalent weight of four stations or substations whose BES Cyber Systems would be classified as medium impact per criterion 2.5. During the Field Test performed by the DT, entities with AWV between 500 and 11,300 were evaluated and no reliability risks to the BES were identified for any entities.

The bright line of 75 MWh is selected to align with pre-existing criteria including (1) the registration criteria for a Distribution Provider (DP) and (2) the registration criteria for a GO. Establishing a threshold is intended to differentiate between non-impactful load serving areas and areas that are more likely to have an impact on the interconnected BES. It was selected to be conservative and is below other established thresholds such as the reporting requirement for uncontrolled loss of firm load resulting from a BES Emergency and firm load shedding resulting from a BES Emergency as documented in EOP-004. EEA conditions were specifically excluded to ensure a Responsible Entity is not disincentivized from providing all available assistance during emergency conditions due to future compliance considerations.

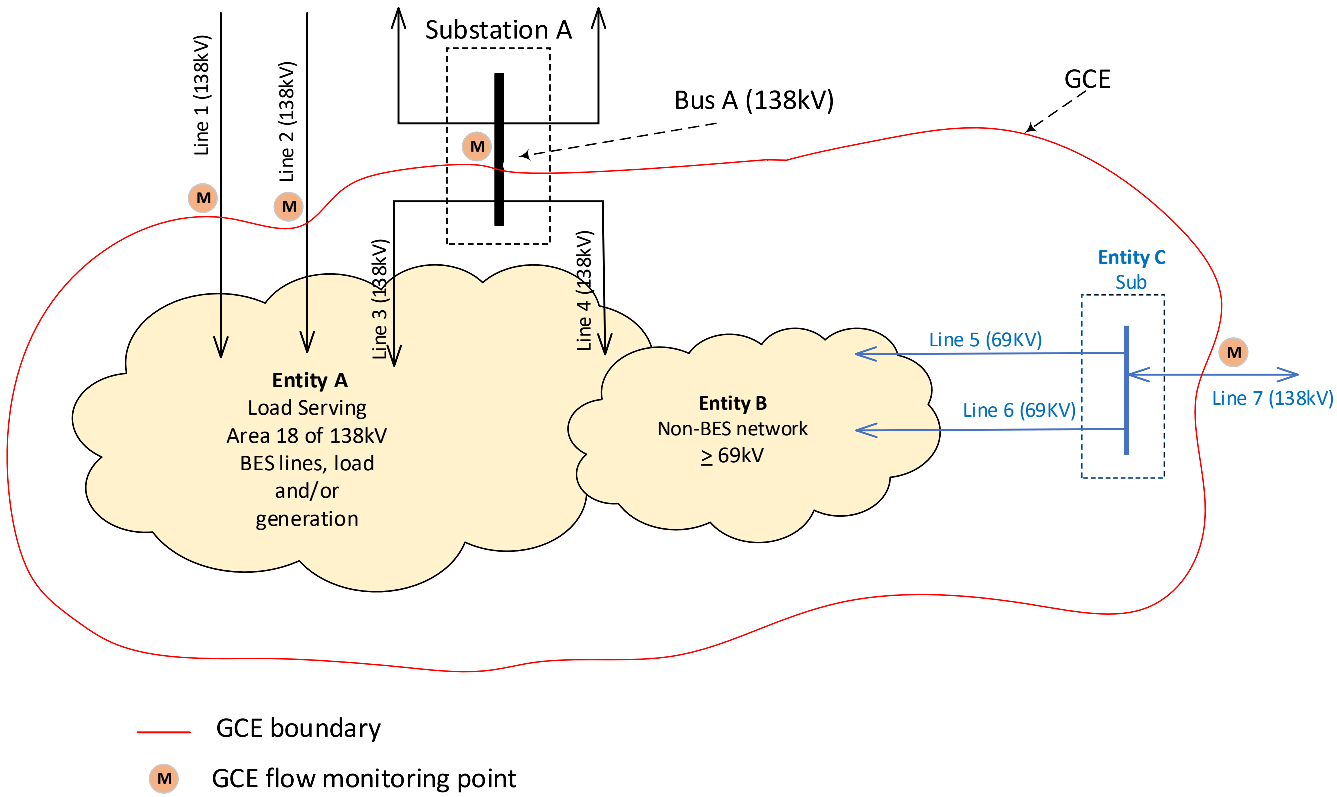
The DT has intentionally constructed the exclusion clause to require an entity to measure gross export from their defined GCE. This accounts for both generation output and flow-through the GCE. It ensures that an entity is unable to define a GCE that contains significant generation that supports the BES or with significant flow-through that impacts the BES.

GCE Example

The GCE must be a contiguous system. It may contain non-BES assets that are operated at 69kV or above and it may contain assets owned/operated by another entity. In the event that a non-BES element is part of the GCE interface, it will need to be included in the gross export calculation.

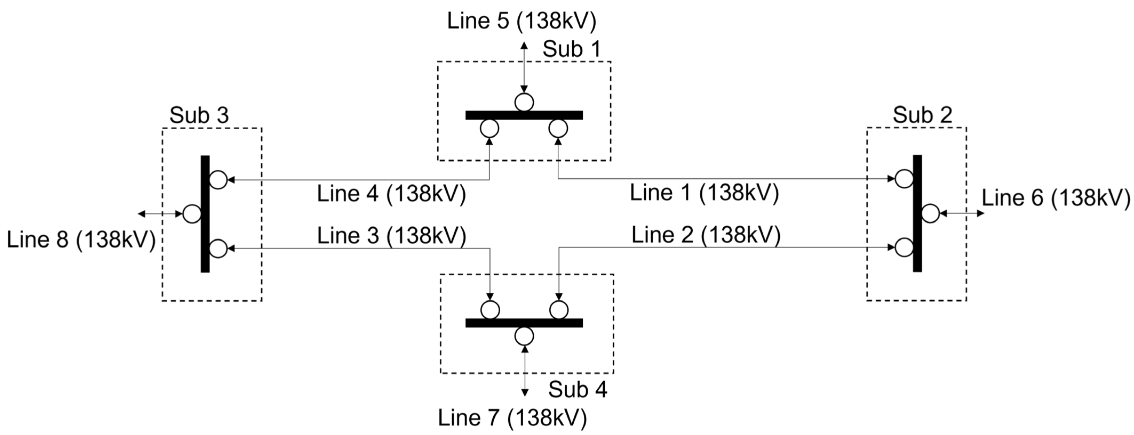
In this example, Entity A defines a GCE that contains all equipment shown in the red boundary below. The GCE interface consists of the flow through Bus A, Line 1, Line 2, and Line 7. The GCE contains equipment owned and operated by Entities A, B and C. To demonstrate compliance with the exclusion clause, Entity A must be able to obtain the necessary data from Entity C for Line 7 to calculate the gross export to demonstrate compliance with CIP-002. The entity must also be able to determine the relevant flow through Bus A, Line 1, Line 2, and Line 7 to demonstrate that gross export from the GCE does not exceed 75 MWh.

In this particular example, Entity A may not have the capability to measure the flow through Bus A; however, the entity may be able to utilize existing measurement points that exist on the four lines that terminate on Bus A to determine the flow as necessary to calculate the hourly integrated gross export from the GCE.



Criterion 2.12 Example 1: Aggregate Weighted Value below 6,000

In example 1 below, BCS are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12 and sum the weighted values for each BES Transmission Line.



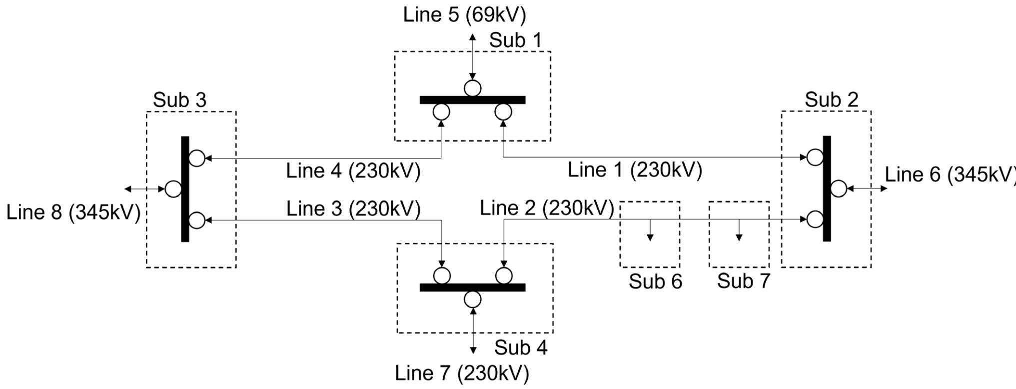
Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2,000, which is below the minimum threshold for the medium impact rating required in criterion 2.12. The BCS associated with the Control Center in this example should be categorized as low impact BCS pursuant to criterion 3.1.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6 Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Criterion 2.12 Example 2: Aggregate Weighted Value exceeds 6,000 with no Exclusion

In example 2 below, BCS are associated with a Control Center that monitors and controls seven BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12 and sum the weighted values for each BES Transmission Line.



Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6,100, which is above the minimum threshold for the medium impact rating required in criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity would be eligible to consider calculating a modified aggregate weighted value that excludes a single GCE in accordance with the exclusion clause; however, in this example, the Responsible Entity either did not choose to pursue an exclusion or did not meet the exclusion criteria. In accordance with criterion 2.12, the BCS associated with the Control Center should be categorized as medium impact BCS.

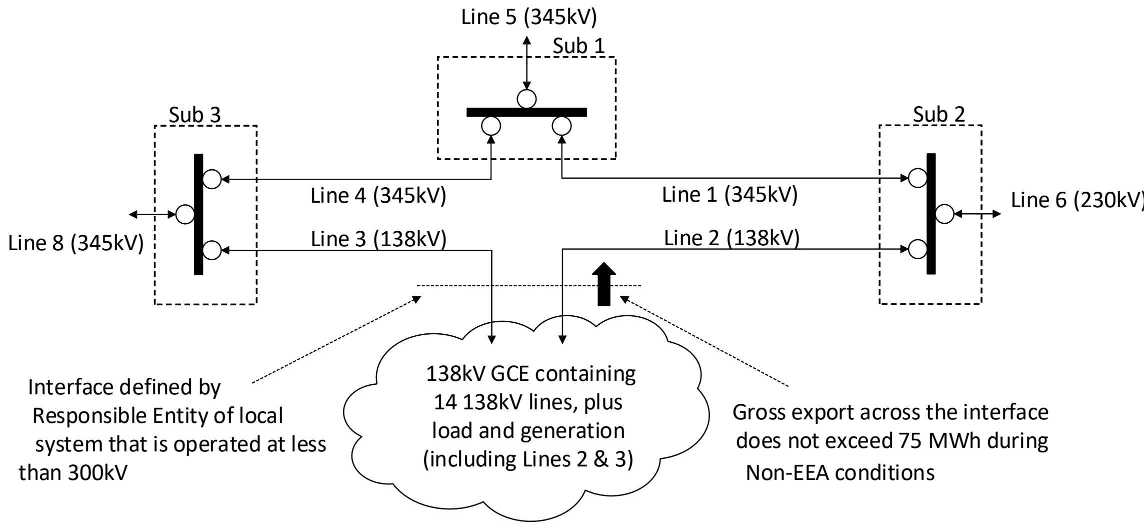
The circles on the diagram indicate the presence of fault-interrupting devices. There are two substations shown (Sub 6 and Sub 7) that are tapped on Line 2 for load serving purposes; however, these substations do not have line fault-interrupting devices that will operate for a fault on Line 2. Therefore, the BES Transmission Line is defined between Sub 2 and Sub 4.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

*Line 5 is less than 100 kV; however, no exception has been obtained through the NERC ROP Exception Process and therefore, the line is not BES.

Criterion 2.12 Example 3: Aggregate Weight Value below 6,000 after Applying GCE Exclusion

In example 3 below, BCS are associated with a Control Center that monitors and controls nineteen BES Transmission Lines, of which 14 are to be excluded from the calculation using the GCE exception. The entity should first calculate its aggregate weighted value, referencing the table located in criterion 2.12. The entity is eligible to calculate a modified aggregate weighted value if the original aggregate weighted value is less than 12,000. In order to calculate the Control Center's modified aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12, and the exclusion language, and sum the weighted values for each BES Transmission Line that is not part of a single GCE that was defined by the entity in accordance with the exclusion clause.



Note: Substation equipment (e.g., transformers) is not shown for simplicity.

Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 9,400, which is above the minimum threshold for the medium impact rating required in criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity is eligible to calculate a modified aggregate weighted value that excludes a single GCE in accordance with the exclusion clause.

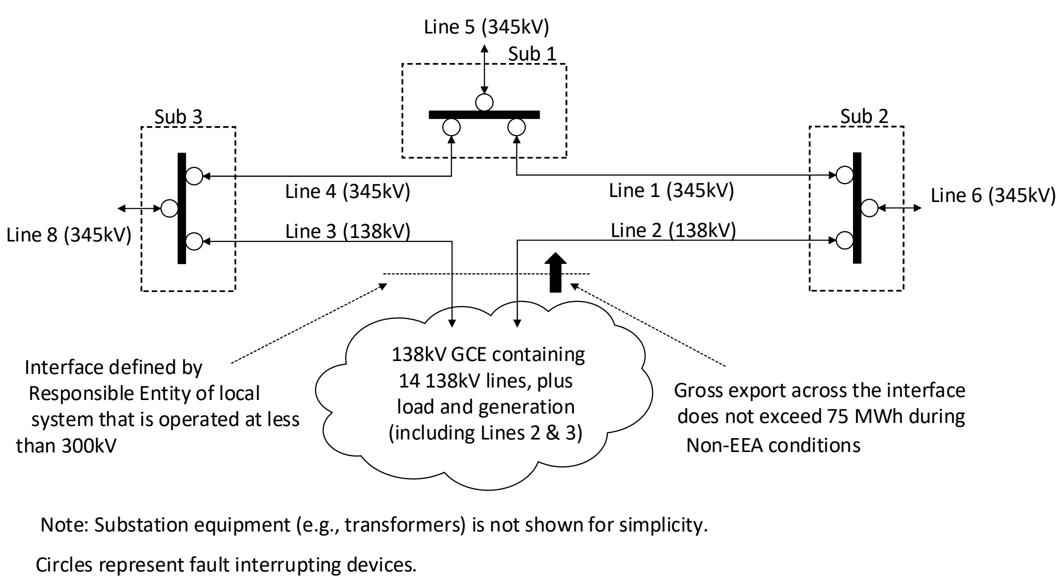
Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 2, Line 3, 12 additional lines	3500
200 kV to 299 kV	700	Line 6	700
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 8	5200
500 kV and above	0	None	0

The calculation of the modified aggregate weighted value is demonstrated below and equates to an aggregate weighted value of 5,900, which is below the minimum threshold for the medium impact rating required in criterion 2.12. The BCS associated with the Control Center in this example should be categorized as low impact BCS pursuant to criterion 3.1.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 6	700
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 8	5200
500 kV and above	0	None	0

*Lines 2 and 3 (along with the 12 additional lines located in the 138 kV GCE) are excluded from the calculation because the Responsible Entity has defined an interface to a GCE that is operated at less than 300kV, where the gross export across the interface does not exceed 75 MWh during non-EEA conditions.

Example 4: Aggregate Weight Value above 6,000 after Applying GCE Exclusion
In example 4 below, BCS are associated with a Control Center that monitors and controls 19 BES Transmission Lines, of which 14 are to be excluded from the calculation using the GCE exception. The entity should first calculate its aggregate weighted value, referencing the table located in criterion 2.12. The entity is eligible to calculate a modified aggregate weighted value if the original aggregate weighted value is less than 12,000. To calculate the Control Center's modified aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12, and the exclusion language, and sum the weighted values for each BES Transmission Line that is not part of a single GCE that was defined by the entity in accordance with the exclusion clause.



The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 10,000, which is above the minimum threshold for the medium impact rating required in criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity is eligible to calculate a modified aggregate weighted value that excludes BES Transmission Lines contained in a single GCE in accordance with the exclusion clause.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 2, Line 3, 12 additional lines	3500
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 6, Line 8	6500
500 kV and above	0	None	0

The calculation of the modified aggregate weighted value is demonstrated below and equates to an aggregate weighted value of 6,500, which is above the minimum threshold for the medium impact rating required in criterion 2.12. In accordance with criterion 2.12, the BCS associated with the Control Center should be categorized as medium impact BCS.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 6, Line 8	6500
500 kV and above	0	None	0

*Lines 2 and 3 (along with the 12 additional lines located in the 138kV GCE system) are excluded from the calculation because the Responsible Entity has defined an interface to a GCE that is operated at less than 300kV, where the gross export across the interface does not exceed 75 MWh during non-EEA conditions.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2021-03 CIP-002

Formal Comment Period Open through October 15, 2024

Now Available

A formal comment period for **draft three of CIP-002-8 — Cyber Security - BES Cyber System Categorization**, is open through **8 p.m. Eastern, Tuesday, October 15, 2024**.

Based on recent board adopted standard CIP-002-7, the posted version for 2021-03 CIP-002 reflects CIP-002-8. The Standards Balloting and Commenting System (SBS) does not allow edits once a ballot is created and/or opened. Even though the standard versioning in the SBS states CIP-002-Y, the version number within this posting is correct and entities will be voting on CIP-002-8.

The drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Commenting

Use the 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.

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

Next Steps

Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 4-15, 2024**.

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

For more information or assistance, contact 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 2021-03 CIP-002” in the Description Box.

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

Comment Report

Project Name:	2021-03 CIP-002 | CIP-002-8 - Draft 3
Comment Period Start Date:	8/29/2024
Comment Period End Date:	10/15/2024
Associated Ballots:	2021-03 CIP-002 CIP-002-Y AB 3 ST 2021-03 CIP-002 Implementation Plan AB 3 OT 2021-03 CIP-002 Non-binding Poll AB 3 NB

There were 63 sets of responses, including comments from approximately 165 different people from approximately 105 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Based on industry comments from informal and formal outreach, the DT has modified the Control Center definition. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and a recommendation for an alternate definition.

2. Language throughout Attachment 1 of CIP-002-8 that referred to the "functional obligations" of the different Registered Entities has been replaced with the term "reliability tasks". This change was incorporated given that the NERC Functional Model is no longer being actively maintained and aligns with CIP-002 language with the existing language of the Control Center definition. Do you agree with the proposed changes to CIP-002-8? Does the change introduce reliability gaps to the Registered Entities? If not, please provide the basis for your disagreement and an alternate proposal.

3. The DT reworded the exclusion clause in Criteria 2.12 to provide clarity and to simplify the concepts. Further, the DT replaced the concept of a group of contiguous transmission Elements (GCTE) with the concept of a group of contiguous Elements to clarify that the group of Elements may contain transmission Elements and non-transmission Elements. Lastly, the 75 MW gross export limitation was changed to 75 MWh to appropriately reflect an hourly integrated gross export, as opposed to an instantaneous measurement within the hour. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

4. For the Implementation Plan, the DT elected to retain 24-month window as it aligns with the established 24-month window that is currently provided to Responsible Entities who identify their first high impact or medium impact BES Cyber System. Further, given that the earliest effective date of CIP-002-8 is April 1, 2026 (aligning with the earliest possible effective date of CIP-002-7), entities will have adequate time to evaluate impacts before the 24-month window commences. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

5. Provide any additional comments for the 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
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Husam Al-Hadidi	Manitoba Hydro (System Preformance)	1,3,5,6	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Jaimin Patal	Saskatchewan Power Coporation (SPC)	1	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Dane Rogers	Oklahoma Gas and Electric (OG&E)	1,3,5,6	MRO
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
					Andrew Coffelt	Board of Public Utilities-Kansas (BPU)	1,3,5,6	MRO
					Peter Brown	Invenergy	5,6	MRO

					Angela Wheat	Southwestern Power Administration	1	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Joshua Phillips	Southwest Power Pool	2	MRO
					Patrick Tuttle	Oklahoma Municipal Power Authority	4,5	MRO
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	TVA RBB	Ian Grant	Tennessee Valley Authority	3	SERC
					David Plumb	Tennessee Valley Authority	1	SERC
					Armando Rodriguez	Tennessee Valley Authority	6	SERC
					Nehtisha Rollis	Tennessee Valley Authority	5	SERC
Manitoba Hydro	Jay Sethi	1,3,5,6	MRO	Manitoba Hydro Group	Nazra Gladu	Manitoba Hydro	1	MRO
					Mike Smith	Manitoba Hydro	3	MRO
					Kristy-Lee Young	Manitoba Hydro	5	MRO
					Kelly Bertholet	Manitoba Hydro	6	MRO
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					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
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Travis Grablander	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC

					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					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
Western Electricity Coordinating Council	Steven Rueckert	10		WECC CIP	Steve Rueckert	WECC	10	WECC
					Morgan King	WECC	10	WECC
					Deb McEndaffer	WECC	10	WECC
					Tom Williams	WECC	10	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power Cooperative (Missouri)	3	SERC

					Gary Dollins	M and A Electric Power Cooperative	3		SERC
					William Price	M and A Electric Power Cooperative	1		SERC
					Olivia Olson	Sho-Me Power Electric Cooperative	1		SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1		SERC
					Heath Henry	NW Electric Power Cooperative, Inc.	3		SERC
					Tony Gott	KAMO Electric Cooperative	3		SERC
					Micah Breedlove	KAMO Electric Cooperative	1		SERC
					Brett Douglas	Northeast Missouri Electric Power Cooperative	1		SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3		SERC
					Mark Riley	Associated Electric Cooperative, Inc.	1		SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6		SERC
					Chuck Booth	Associated Electric Cooperative, Inc.	5		SERC
					Jarrod Murdaugh	Sho-Me Power Electric Cooperative	3		SERC

1. Based on industry comments from informal and formal outreach, the DT has modified the Control Center definition. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and a recommendation for an alternate definition.

Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; - Rebika Yitna	
Answer	No
Document Name	
Comment	
Putting the Transmission Owner (TO) definition separate from the original definition is acceptable; however, the language should be consistent and include the Bulk Electric System in the definition. Suggested wording update for the TO Control Center definition: "One or more facilities of a Transmission Owner that have the capability to control the Bulk Electric System and to control Transmission Facilities at two or more locations in real-time using SCADA, including their associated data centers, and excluding field Cyber Assets used for telemetry."	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA finds the second part of the proposed Control Center definition to be vague and confusing. The research required to find and understand the examples and rationale are too convoluted and spread out. BPA recommends rewording the section after the 'or' to at least define where a person will find explanations of the intent. The use of the term facilities, lower case, should be replaced with another term such as 'locations' or 'sites'.. The use of the word "capability" is too open in interpretation. BPA recommends striking "capability" from the definition.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	No
Document Name	
Comment	

The definition is too prescriptive on technology. SCADA systems are only one way to operate elements at BES Facilities. Some Control Centers may operate BES elements via other technology such as a relay network or another industrial control system not defined as SCADA.

Likes 0	
Dislikes 0	

Response

Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan

Answer	No
Document Name	

Comment

Clarity on "SCADA system that can control the transmission Facility". The standard specifically excludes "Field Assets used for Telemetry" but does not also exclude **regional data concentrators**. The new verbiage only talks about the capability to control -> This needs to be quantified as available operator interfaces designed for control of these 2 or more transmission substations; not the ability to configure an interface for control. An argument can be made that a regional data concentrator "could" be used to issue controls. Although impractical for grid control, however it is possible. Hydro One suggestion is to change "capability" to "authority" in the definition on Pg.2.

Likes 0	
Dislikes 0	

Response

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	No
Document Name	

Comment

In the last sentence "Cyber Asset" should be replaced with BCS.

The following network architecture scenarios are not limited to "facilities":

For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

1. If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers, but no one is assigned to that desk, is the engineering office a Control Center? or

2. If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or

3. If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or

4. If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center?

5. If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a Control Center?

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

In the last sentence “Cyber Asset” should be replaced with BCS.

The following network architecture scenarios are not limited to “facilities”:

For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

1. If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers, but no one is assigned to that desk, is the engineering office a Control Center? or
2. If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or
3. If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or
4. If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center?
5. If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a Control Center?

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 appreciates the SDT’s efforts to incorporate the need for TOs to be included in the definition, while recognizing that the rest of the Control Center definition is well understood. The addition of the TO language may inadvertently bring HVDC stations into scope and so the MRO NSRF recommends adding an exclusion or clarifying information that this "Excludes station to station communication for HVDC control functions."

Likes 0	
Dislikes 0	

Response

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	No
Document Name	

Comment

The formatting of the revised Control Center definition is confusing where it uses the term "OR". Use of all upper case letters within NERC Standards has generally implied use of an abbreviation. SMUD recommends replacing this term with "or" and reformatting the definition to prevent the use of a second paragraph solely to include TO facilities. The following proposed edit to the Control Center definition is minor and could be made in the final draft.

Control Center –

1) One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real time to perform the reliability tasks, including their associated data centers, of:

- a Reliability Coordinator,
- a Balancing Authority,
- a Transmission Operator of transmission Facilities at two or more location, or
- a Generator Operator for generation Facilities at two or more locations, or

2) One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding filed Cyber Assets used for telemetry.

Likes 0	
Dislikes 0	

Response

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1

Answer	No
Document Name	

Comment

Per NIPSCO's comments under #5 below, we believe that the gap that this Control Center definition change is meant to address is best addressed in the registration process.

Likes 0	
Dislikes 0	

Response

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	No
Document Name	

Comment

Manitoba Hydro agrees with the direction of the SDT to add an additional definition for a TO control center and leave the rest of the definition unchanged and thanks the SDT for their careful consideration of the definition. The use of the defined term "SCADA" greatly helps to clarify and differentiate between a Control Center (and associated Control Center Cyber Asset) and a remote access connection or local field control.

Manitoba Hydro requests additional clarification be added to the definition for HVDC systems. These are treated as a single Facility that can span a large distance. In order to have local control over HVDC output, there is communication that goes to the other end of the system. In a broad sense this could be considered a SCADA system, however in a practical sense this is considered local control of the HVDC Facility. Manitoba Hydro suggests the definition be amended to specifically address this by adding the following:

"Excludes station to station communication for HVDC control functions."

Manitoba Hydro requests additional clarification in the technical rational or standard to differentiate between local and remote control. When a control room is located at a Transmission station, and that control room has the remote control over one other location, in addition to local control, it is not clear if this is considered two or more locations. This could be clarified in the technical rational or the following modification to the control center definition is proposed:

Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have **Cyber Assets with** the capability to **remotely** control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry **and station to station communication for HVDC control functions**.

Likes 0	

Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
In the last sentence of the Control Center definition, Cyber Assets should be replaced with BCS	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	No
Document Name	
Comment	
The definition as proposed is unclear regarding the number of Facilities at another location that must be controlled in order to be considered a Control Center. TVA suggests revise the Control Center definition to be consistent with the examples provided in the Technical Rationale, which clarifies that there must be control of at least two Facilities at another distinct location to be considered a Control Center. In addition, TVA disagrees with the change from “facilities hosting operating personnel” to “facilities having the capability to control transmission Facilities”. The proposed language is inappropriately over-broad and has the potential to errantly identify Transmission Facilities as Control Centers, a function they were never intended to execute.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
• SERC appreciates the ongoing efforts to refine the CIP-002 standard. SERC does believe that the changes to the Control Center definition have improved its clarity and removed gaps. However, SERC has not found support in the field trial or in other data presented in the various	

SARs to support the removal for consideration of field Cyber Assets used for telemetry. These devices collectively are the ‘eyes and ears’ of the Control Center for providing the decisional data and wide-area situational awareness, and the broad loss of field telemetry systems has been implicated in causing the inoperability of Control Centers in past NERC Lessons Learned documents. Only considering the impact of singular telemetry devices on the field location they are located at would seem to overly credit the redundancy of having many telemetry devices at the expense of providing CIP protections for any of them, instead of considering them as part of the systems which provide critical data for the Control Center to perform its reliability. If the SDT wishes to address the recently added SAR by suggesting complete removal of these devices from CIP consideration, perhaps an additional field trial or data gathering would provide such support. Even without such global removal language, an entity could provide evidence that the loss, degradation, or misuse such telemetry Cyber Systems do not impact the reliability tasks that they specifically perform if that was the case.

In addition, we continue to maintain that limiting inclusion to only those TO facilities using SCADA protocols for control may introduce a reliability gap where such control is affected using terminal servers, remote management protocols to HMIs, or other similar modern means for remote control. A suggestion may be to review the changes made in CIP-005-6 and CIP-005-7 to describe ‘system-to-system’ relationships between Cyber Assets, which is protocol agnostic and provides some future growth room without requiring standards modification.

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

In the last sentence “Cyber Asset” should be replaced with BCS.

The following network architecture scenarios are not limited to “facilities”:

For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system:

1. If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers, but no one is assigned to that desk, is the engineering office a Control Center? or

2. If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or

3. If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or

4. If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center?

5. If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a Control Center?

Likes 0	

Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power supports NSRF's comments. Minnesota Power strongly recommends adding the clarification statement, "Excludes station to station communication for HVDC control functions," to the revised definition of a Control Center.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	
NV Energy appreciates the SDT's efforts to incorporate the need for TOs to be included in the definition, while recognizing that the rest of the Control Center definition is well understood. The addition of the TO language may inadvertently bring HVDC stations into scope and so NV Energy recommends adding an exclusion or clarifying information that this "Excludes station to station communication for HVDC control functions."	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	No
Document Name	
Comment	
Pattern Energy has concerns with the new proposed language for the definition of a Control Center.	

First, the repeat use of ‘facilities’ and ‘Facilities’ will cause unintended interpretations. We do understand that ‘facilities’ is meant to describe the location hosting SCADA, but how the definition is currently written this is not apparently clear.

Second, transmission Facilities is not defined in the sense of which entity/who is responsible to determine what equipment is included in one transmission Facility versus what equipment should be included in another transmission Facility. This will lead to inconsistencies in application and enforcement of the definition. Pattern Energy suggests that the Transmission Owner for the equipment determine what equipment is included in which transmission Facility.

Pattern Energy suggests the following language to remove the aforementioned concerns.

“. . . One or more Transmission Owner facilities, including their associated data centers, and excluding field Cyber Assets used for telemetry, that have the capability in real-time using Supervisory Control and Data Acquisition (SCADA) and host the SCADA, to control multiple transmission Facilities at two or more locations, with the equipment that compromise the transmission Facility being defined by the Transmission Owner.”

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

It is not clear if the additional text: "One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry. " implies that "operating personnel" are required to be present to monitor and control the BES in real-time to perform reliability tasks. The role of a Transmission Owner is not to monitor and control BES assets for real-time reliability purposes, but to monitor them for maintenance purposes.

If the TO does not have to operating personnel hosted in a location (that allows for the control of two or more BES transmission Facilities), are they held to a higher standard than the RC, TOP, and BA entities? The RC, TOP and BA entities are clearly required to be hosting operating personnel according to their applicability in the definition.

As an , where an unmanned substation has control of local transmission switching for two different switchyards. Operating personnel are not hosted in the location, but SCADA controls allow for the control of two or more transmission Facilities. The proposed definition identifies this as a Control Room. The fact may be that the two local transmission Facilities are within the same fencing and at the same physical location. Is the intent of the drafting team to define these as control centers?

Likes 0	
Dislikes 0	

Response

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	No
Document Name	
Comment	
In the last sentence “Cyber Asset” should be replaced with BCS.	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports NPCC Regional Standards Committee’s comments.	
Likes 0	
Dislikes 0	
Response	

Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
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	

While FirstEnergy supports the proposed definition, we suggest the following edit to ensure that BES falls under the Control Center definition:

One or more facilities of a Transmission Owner that have the capability to control **BES** Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

Likes 0	
Dislikes 0	
Response	

Navodka Carter - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	
Comment	

CenterPoint Energy Houston Electric, LLC (CEHE) does not oppose the proposed changes. The proposed modifications to the Control Center definition addresses prior concerns that CEHE had with the new terminology.

Likes 0	
Dislikes 0	
Response	

Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	Yes
Document Name	
Comment	

Duke Energy supports the modified Control Center definition and thanks the drafting team for their work.

Likes 0	
Dislikes 0	
Response	

Matt Carden - Southern Company - Southern Company Services, Inc. - 1

Answer	Yes
Document Name	
Comment	

Southern Company and EEI supports the revisions to the Control Center definition and appreciates the informal outreach conducted by the drafting team ahead of the formal comment and ballot period.

Likes 0	
Dislikes 0	
Response	

James Keele - Entergy - 3

Answer	Yes
Document Name	
Comment	

I would like to see expanded definitions for the GOP functions ie. the difference between GOP in a control center vs GOP in a power plant (operator).

Likes 0	
Dislikes 0	
Response	

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	
Comment	

EEI supports the revisions to the Control Center definition and appreciates the informal outreach conducted by the drafting team ahead of the formal comment and ballot period.

Likes 0	
Dislikes 0	
Response	

Beth Smail - AEP - 1,3,5,6 - MRO,Texas RE,RF

Answer	Yes

Document Name	
Comment	
AEP agrees with the latest revisions to the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 1	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	

Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon is responding in support of the EEI to this question.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon is responding in support of the EEI comments to this question.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	

AZPS agrees	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
SPP supports the SDT's efforts to include the need for TOs to be included in the definition, while recognizing that the rest of the Control Center definition is well understood.	
Likes 0	
Dislikes 0	
Response	
Roger Perkins - Southern Maryland Electric Cooperative - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adam Peterson - Cedar Falls Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Joanne Anderson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gladys DeLaO - CPS Energy - 1,3,5	
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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
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	
Stacy Engelmann - City of College Station - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 6, 5, 1; Sarah Blankenship, 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	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - LaTroy Brumfield On Behalf of: Amy Wilke, American Transmission Company, LLC, 1; - LaTroy Brumfield	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF does not have a position on the modified Control Center definition as our focus is based on the presective of a GO/GOP.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	

Document Name	
Comment	
ITC has no comment.	
Likes 0	
Dislikes 0	
Response	

2. Language throughout Attachment 1 of CIP-002-8 that referred to the "functional obligations" of the different Registered Entities has been replaced with the term "reliability tasks". This change was incorporated given that the NERC Functional Model is no longer being actively maintained and aligns with CIP-002 language with the existing language of the Control Center definition. Do you agree with the proposed changes to CIP-002-8? Does the change introduce reliability gaps to the Registered Entities? If not, please provide the basis for your disagreement and an alternate proposal.

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC Regional Standards Committee's comments.

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	

Comment

The term "reliability tasks" adds no additional clarity. Many transmission owners only manage maintenance, and not operations of their systems. The problem is rooted in the registration where, if an entity does perform TOP reliability tasks, the CEA should force them to be properly registered as a TOP. The Drafting Team has limited ability to address this issue, however, the Drafting Team should recommend that the NERC Functional Model be resurrected and brought up to current industry practices as part of this project.

Industry changes, Markets, technology, and business practices have drastically changed how entities act and interact. The NERC Functional Model was an excellent guidance document for the Drafting Teams to ensure consistency and appropriately assign responsibilities. The industry and Drafting Teams still utilize terms such as "functional obligations" and "reliability tasks", but the original reference of the Functional Model is long gone. These terms are now buzz words with no defined or agreed upon meaning, and they add no clarity to compliance anymore.

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	
NPCC RSC agrees with the proposed changes with the removal of the functional obligations in Attachment 1 but suggest splitting out part 1.3 in Attachment 1- Impact Rating Criteria for TOP and TO. The TOP should have similar wording as per the Control Center definition to the RC, BA, and GOP and the TO should be exclusive to part 1.3 wording.	
Likes 0	
Dislikes 0	
Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
• SERC appreciates the ongoing efforts to refine the CIP-002 standard. SERC does believe that the changes to the criteria do help in addressing the obsolescence of the Functional Model, however it is still not clear in the plain language of the requirement where the 'reliability tasks' of each Responsible Entity are to be derived. To establish a clear linkage for this undefined phrase, perhaps clearly stating that if a task-based responsibility exists in another NERC Reliability Standard, that constitutes a reliability task which bears accounting for in CIP-002-8. Past usage of undefined or non-specific vestigial terminology in CIP-002-5 has led to misunderstanding and inconsistent interpretations.	
Likes 0	
Dislikes 0	
Response	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	
NPCC RSC agrees with the proposed changes with the removal of the functional obligations in Attachment 1 but suggest splitting out part 1.3 in Attachment 1- Impact Rating Criteria for TOP and TO. The TOP should have similar wording as per the Control Center definition to the RC, BA, and GOP and the TO should be exclusive to part 1.3 wording.	
Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	

Answer	No
Document Name	
Comment	

NPCC RSC agrees with the proposed changes with the removal of the functional obligations in Attachment 1 but suggest splitting out part 1.3 in Attachment 1- Impact Rating Criteria for TOP and TO. The TOP should have similar wording as per the Control Center definition to the RC, BA, and GOP and the TO should be exclusive to part 1.3 wording.

Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	No
Document Name	
Comment	

AECI does agree that references to "functional obligations" should be revised due to the reason cited; however, all references to "reliability tasks" should align with NERC stanandard PER-005-2 language and be referred to as "BES company specific Real-time reliability related tasks" to lessen the opportunity for confusion, auditor interpretation, and reliability gaps.

Likes 0	
Dislikes 0	
Response	

Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No
Document Name	
Comment	

Duke Energy recommends that “reliability tasks” be included in the High Impact Rating Criteria in Attachment 1, 1.3. for Transmission Operators (TOPs) and Transmission Owners (TOs). The “functional obligations” language in CIP-002-5.1a, Attachment 1, 1.3. for the TOP was removed, but not replaced with “reliability tasks”. The language “perform the reliability tasks” is included in the draft of CIP-002-8 in Attachment 1, 1.1. for the RC, 1.2 for the BA, and even 1.4. for the GOP, even though PER-005-2 does not include a requirement for the GOP to *“create a list of BES company-specific Real-time reliability-related tasks” (reliability tasks list)*. TOPs and TOs have reliability tasks as well as the other functional entities (RC, BA, GOP) included in Attachment 1, and adding “perform the reliability tasks” to 1.3. would provide consistency. Transmission Owners that have the capability to control Facilities at two or more locations in Real-time using SCADA per the revised Control Center definition, would be required to create a reliability tasks list per PER-005-2. The TO entity developing the reliability tasks list would take into account the direction under their TOP. The intent of adding “perform

the reliability tasks" to Attachment 1, 1.3. is not necessarily because of or to refer to PER-005-2, but only to point out that a TOP and TO also have reliability tasks.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees with the term "reliability tasks" and has not identified any concerns over reliability gaps.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS supports the use of the term "reliability tasks", however since it is not a defined term, it will be ambiguous without proper expansion within guidelines and technical basis or some other form of guidance.	

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

The NAGF agrees with the proposed changes for CIP-002-8.

Likes 0	
Dislikes 0	

Response

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon is responding in support of the EEI comments to this question.

Likes 0	
Dislikes 0	

Response

Kinte Whitehead - Exelon - 3

Answer	Yes
Document Name	

Comment

Exelon is responding in support of the EEI to this question.

Likes 0	
Dislikes 0	

Response

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro is supportive of the changes the drafting team has made and does not see any gaps introduced by the term “reliability tasks”.	
Likes 0	
Dislikes 0	
Response	

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Please see ACES comments, AEPC has signed on to ACES comments.	
Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 2	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Beth Smail - AEP - 1,3,5,6 - MRO,Texas RE,RF	
Answer	Yes
Document Name	
Comment	
AEP agrees with the cited changes in Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	

Answer	Yes
Document Name	
Comment	
The MRO NSRF agrees with the term “reliability tasks” and has not identified any concerns over reliability gaps.	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the use of the term “reliability tasks” instead of “functional obligations.” We have not identified reliability gaps associated with this change.	
Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with EEI supporting the use of the term “reliability tasks” instead of “functional obligations.” We have not identified reliability gaps associated with this change.	
Likes 0	
Dislikes 0	
Response	
Navodka Carter - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	

Comment	
CEHE accepts the proposed changes to utilize the term "reliability tasks." At present, CEHE has not identified any reliability gaps posed by the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - LaTroy Brumfield On Behalf of: Amy Wilke, American Transmission Company, LLC, 1; - LaTroy Brumfield	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 6, 5, 1; Sarah Blankenship, 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	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3,	

6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mike Magruder - Avista - Avista Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
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	
Gladys DeLaO - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joanne Anderson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Adam Peterson - Cedar Falls Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Perkins - Southern Maryland Electric Cooperative - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	

ITC has no comment.

Likes 0	
Dislikes 0	

Response

3. The DT reworded the exclusion clause in Criteria 2.12 to provide clarity and to simplify the concepts. Further, the DT replaced the concept of a group of contiguous transmission Elements (GCTE) with the concept of a group of contiguous Elements to clarify that the group of Elements may contain transmission Elements and non-transmission Elements. Lastly, the 75 MW gross export limitation was changed to 75 MWh to appropriately reflect an hourly integrated gross export, as opposed to an instantaneous measurement within the hour. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan

Answer	No
Document Name	

Comment

This criterion should be clearer to identify the associated Transmission BES Cyber System and not the physical Control Center. There are many utilities that operate a Transmission and Distribution function out of the same control center. This would be a good opportunity to clearly articulate the difference between Control Center as a place (physical location) and a device (BES Cyber System controlling the BES as per the definition).

Likes 0	
Dislikes 0	

Response

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	No
Document Name	

Comment

This is not specific to this question and may identify an issue that is not technically possible but there is a gap between the X99 and Y00 "Characteristics of Line" levels. A 199.5kV line is not rated on this table.

Request explicit explanation (in the Standard) of the weighted value of zero for "Each BES Transmission Line 500 kV and above." (see Criterion 2.5) We agree with the weighted value. Please correct as needed – we understand that a Control Center with such a Transmission Line is High Impact.

The language for the exemption seems to allow for the exclusion of a Controls Center as medium impact if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines, even if these lines are not tied together within the Transmission system controlled by the Control Center.

The 12-month period portion of the language makes it unclear how new transmission lines are handled even if it is known that they will increase the "net export" beyond the 75MW threshold.

The SDT should provide clarity on if a change in the "net export" fluctuates around or exceeds for the first time, the 75MW threshold. When is exceeding the threshold an "unplanned change", allowing for a 2-year implementation and when is it a "planned change" requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center loses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then loses the exemption, if there are no other medium impact programs in place, do they always get 2 years to either implement the plan or pray that they gain the exemption before the implementation period is over?

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

This is not specific to this question and may identify an issue that is not technically possible but there is a gap between the X99 and Y00 “Characteristics of Line” levels. A 199.5kV line is not rated on this table.

Request explicit explanation (in the Standard) of the weighted value of zero for “Each BES Transmission Line 500 kV and above.” (see Criterion 2.5) We agree with the weighted value. Please correct as needed – we understand that a Control Center with such a Transmission Line is High Impact.

The language for the exemption seems to allow for the exclusion of a Controls Center as medium impact if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines, even if these lines are not tied together within the Transmission system controlled by the Control Center.

The 12-month period portion of the language makes it unclear how new transmission lines are handled even if it is known that they will increase the “net export” beyond the 75MW threshold.

The SDT should provide clarity on if a change in the “net export” fluctuates around or exceeds for the first time, the 75MW threshold. When is exceeding the threshold an “unplanned change”, allowing for a 2-year implementation and when is it a “planned change” requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center loses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then loses the exemption, if there are no other medium impact programs in place, do they always get 2 years to either implement the plan or pray that they gain the exemption before the implementation period is over?

Likes 0	
Dislikes 0	

Response

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB

Answer	No
Document Name	

Comment

Transmission lines operated at <100kV are not part of the BES and should not be included in the aggregate weighted value model.

Likes 0	
Dislikes 0	

Response	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
• SERC appreciates the ongoing efforts to refine the CIP-002 standard. The changes to the Criterion to improve clarity, however there is still uncertainty and a lack of clarity in the standard or Implementation Plan on the timeline for an entity who exceeds the 75MWH exclusion threshold to recalculate their CIP-002-8 inclusions. We again suggest including a specific example in the Implementation Plan to address this occurrence to reduce ambiguity.	
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	
This is not specific to this question and may identify an issue that is not technically possible but there is a gap between the X99 and Y00 "Characteristics of Line" levels. A 199.5kV line is not rated on this table. Request explicit explanation (in the Standard) of the weighted value of zero for "Each BES Transmission Line 500 kV and above." (see Criterion 2.5) We agree with the weighted value. Please correct as needed – we understand that a Control Center with such a Transmission Line is High Impact. The language for the exemption seems to allow for the exclusion of a Controls Center as medium impact if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines, even if these lines are not tied together within the Transmission system controlled by the Control Center. The 12-month period portion of the language makes it unclear how new transmission lines are handled even if it is known that they will increase the "net export" beyond the 75MW threshold. The SDT should provide clarity on if a change in the "net export" fluctuates around or exceeds for the first time, the 75MW threshold. When is exceeding the threshold an "unplanned change", allowing for a 2-year implementation and when is it a "planned change" requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center loses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then loses the exemption, if there are no other medium impact programs in place, do they always get 2 years to either implement the plan or pray that they gain the exemption before the implementation period is over?	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE continues to be concerned that the way of calculating the risk may not cover all scenarios and does not account for differences in Transmission lines. Texas RE has taken the position that that BCS used to perform the functional obligations of a Transmission Operator should remain categorized as medium impact or high impact. The risk the BCS at a Control Center poses to the reliable operation of the BES is not easily covered by counting the quantity of transmission lines operated. Two Control Centers operating the same number of transmission lines may pose very different risks to the BES. For example, if one Control Center is predominantly operating Transmission lines at substations interconnected with Generation Facilities it may pose more risk than a Control Center operating Transmission lines at substations that are not interconnected with Generation Facilities.

Texas RE proposes the following language for criterion 2.12:

Each Control Center or backup Control Center operated by a Transmission Operator or owned by a Transmission Owner.

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

Using the 75 MWh gross export is problematic and will lead to gaming. There is no precedent for using a MWh value. Instead, the Drafting Team should consider the maximum line rating, since this allows for any situation where power flows may change.

Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No

Document Name	
Comment	
OPG supports NPCC Regional Standards Committee's comments.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
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 concerns with the proposed changes.	
Likes 0	
Dislikes 0	
Response	
Navodka Carter - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	

CEHE accepts the proposed changes to the exclusion clause in Criteria 2.12.

Likes 0	
Dislikes 0	

Response

Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	Yes
Document Name	

Comment

Duke Energy does not oppose the changes to the exclusion clause .

Likes 0	
Dislikes 0	

Response

Matt Carden - Southern Company - Southern Company Services, Inc. - 1

Answer	Yes
Document Name	

Comment

Southern Company agrees with EEI who does not have concerns about the revisions to the exclusion clause.

Likes 0	
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	Yes
Document Name	

Comment

Tacoma Power agrees with the proposed changes, but has a minor comment for clarification in Criteria 2.12. The Criteria 2.12 includes a challenging description of how to determine the aggregate weighted value.

Suggest replacing:

‘The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per BES Transmission Line” that is monitored and controlled by the Control Center or backup Control Center shown in the table below.’

With:

‘The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per BES Transmission Line” **shown in the table below, for lines** that **are** monitored and controlled by the Control Center or backup Control Center.’

Likes 0	
Dislikes 0	

Response

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI does not have concerns about the revisions to the exclusion clause.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	Yes
Document Name	

Comment

The MRO NSRF appreciates the SDT’s work to find a balance between ensuring the reliability and security of the BES without unduly burdening smaller entities which pose less risk. The MRO NSRF does not have any specific comments related to the proposed language, given the published results of the DT field tests.

As entities implement the exclusion clause offered in 2.12, the MRO NSRF enourages the use of security awareness efforts and ensuring strong security protections are in place for any Control Center, regardless of impact level or minimum requirements.

Likes 0	
Dislikes 0	
Response	
Beth Smail - AEP - 1,3,5,6 - MRO,Texas RE,RF	
Answer	Yes
Document Name	
Comment	
AEP does not have concerns about the revisions to the exclusion clause.	
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	
A note should be added to the table in Impact Rating Criteria 2.12 regarding transmission lines less than 100 kV to clarify that only transmission lines that are less than 100 kV which have been specifically designated as part of the BES via the NERC Rules of Procedure Exception Process (inclusions) are to be used in the calculation of the aggregated weighted value as stated in the Technical Rational. This is important because registered entities are evaluated based on the language in the Standard and not the language in the Technical Rational. For Transmission Operators (TOPs) and Transmission Owners (TOs) with an approved BES Exception (exclusion) for certain facilities, an additional paragraph or bullet should be added to the Exclusion section of Criteria 2.12 to clarify those facilities may be excluded from the calculation of the aggregated weighted value of Criteria 2.12. For example, if a TOP and/or TO has an approved Local Network Exclusion of its 100 kV network, then those transmission lines covered by that approved exclusion are not included in the calculation of aggregated weighted value for Criteria 2.12.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes

Document Name	
Comment	

Ameren agrees with and supports NAGF and EEI comments.

Likes 0	
Dislikes 0	
Response	

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	Yes
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 3

Likes 0	
Dislikes 0	
Response	

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	
Comment	

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	
Response	

Kinte Whitehead - Exelon - 3

Answer	Yes

Document Name	
Comment	
Exelon is responding in support of the EEI to this question.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon is responding in support of the EEI comments to this question.	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	

NV Energy appreciates the SDT’s work to find a balance between ensuring the reliability and security of the BES without unduly burdening smaller entities which pose less risk. NV Energy does not have any specific comments related to the proposed language, given the published results of the DT field tests. As entities implement the exclusion clause offered in 2.12, NV Energy enourages the use of security awareness efforts and ensuring strong security protections are in place for any Control Center, regardless of impact level or minimum requirements.	
Likes 0	
Dislikes 0	
Response	
Roger Perkins - Southern Maryland Electric Cooperative - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Adam Peterson - Cedar Falls Utilities - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Joanne Anderson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gladys DeLaO - CPS Energy - 1,3,5	
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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
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	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	

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	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 6, 5, 1; Sarah Blankenship, 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	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
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	
Jeffrey Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
LaTroy Brumfield - LaTroy Brumfield On Behalf of: Amy Wilke, American Transmission Company, LLC, 1; - LaTroy Brumfield	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF does not have input for this question as our focus is based on the presective of a GO/GOP.	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	

Document Name	
Comment	
ITC has no comment.	
Likes 0	
Dislikes 0	
Response	

4. For the Implementation Plan, the DT elected to retain 24-month window as it aligns with the established 24-month window that is currently provided to Responsible Entities who identify their first high impact or medium impact BES Cyber System. Further, given that the earliest effective date of CIP-002-8 is April 1, 2026 (aligning with the earliest possible effective date of CIP-002-7), entities will have adequate time to evaluate impacts before the 24-month window commences. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Hillary Creurer - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
If HVDC control functions are considered in scope as a Control Center, additional time would be necessary to meet the additional requirements.	
Likes 0	
Dislikes 0	
Response	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
The proposed 24-month implementation plan has the potential to become very limiting for large entities that could have a large number of new Facilities and facilities due to the current revision of the standard. BPA recommends additional time of 6-12 months to account for updating tools and models in use for the current version of the standard and to allow for changes due to standard effectiveness occurring in the middle of a calendar year.	
Likes 0	
Dislikes 0	
Response	
Melanie Wong - Seminole Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response
Ijad Dewan - Ijad Dewan On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Ijad Dewan

Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marcus Bortman - APS - Arizona Public Service Co. - 6	
Answer	Yes
Document Name	
Comment	
AZPS agrees	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	Yes
Document Name	
Comment	
The NAGF agrees with the proposed Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	

Answer	Yes
Document Name	
Comment	
Exelon is responding in support of the EEI comments to this question.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon is responding in support of the EEI to this question.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO, Group Name Manitoba Hydro Group	
Answer	Yes
Document Name	
Comment	
Manitoba Hydro agrees with the implementation timeline that balances giving entities enough time to complete any required changes while implementing necessary security measures.	
Likes 0	
Dislikes 0	
Response	
Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples	
Answer	Yes

Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) and the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 4	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Ameren agrees with and supports NAGF and EEI comments.	
Likes 0	
Dislikes 0	
Response	
Beth Smail - AEP - 1,3,5,6 - MRO,Texas RE,RF	
Answer	Yes
Document Name	
Comment	
AEP does not have concerns with the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI does not have concerns with the Implementation Plan.

Likes 0	
Dislikes 0	
Response	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Southern Company agrees with EEI who does not have concerns with the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy supports the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Navodka Carter - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CEHE has no comments.	

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy has no concerns with the proposed changes.

Likes 0	
Dislikes 0	

Response

LaTroy Brumfield - LaTroy Brumfield On Behalf of: Amy Wilke, American Transmission Company, LLC, 1; - LaTroy Brumfield

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Mia Wilson - Southwest Power Pool, Inc. (RTO) - 2 - MRO,WECC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
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	
George E Brown - Pattern Operators LP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeffrey Ipsaro - Silicon Valley Power - City of Santa Clara - 3,4,5	
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	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 6, 5, 1; Sarah Blankenship, 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	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Chantal Mazza On Behalf of: Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
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	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - 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	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stacy Engelmann - City of College Station - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
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	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
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	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
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	
Gladys DeLaO - CPS Energy - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joanne Anderson - Public Utility District No. 2 of Grant County, Washington - 1,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Adam Peterson - Cedar Falls Utilities - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rebika Yitna - Rebika Yitna On Behalf of: David Weekley, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Roger Perkins - Southern Maryland Electric Cooperative - 1,3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	

Document Name	
Comment	
ITC has no comment.	
Likes 0	
Dislikes 0	
Response	

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

Roger Perkins - Southern Maryland Electric Cooperative - 1,3	
Answer	
Document Name	
Comment	
Thanks to the SDT for it's continued hard work and allowing us to comment.	
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	

Gladys DeLaO - CPS Energy - 1,3,5	
Answer	
Document Name	
Comment	
CPS Energy does not have any additional comments.	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	
Document Name	
Comment	
No additional comments.	
Likes 0	
Dislikes 0	
Response	

Navodka Carter - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	
Document Name	
Comment	
CEHE has no additional comments.	
Likes 0	
Dislikes 0	
Response	

Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	
Document Name	
Comment	
Duke Energy thanks the Drafting team for their work on the Control Center definition and the CIP-002 revisions.	
Likes 0	
Dislikes 0	
Response	

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	

Document Name	
Comment	

Why is criterion 2.12 applicable to Transmisison Owners rather than just Transmission Operators? The NERC glossary definitions of each are as follows:

Transmisison Owner: The entity that owns and maintains transmission Facilities

Transmission Operator: The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission Facilities.

This crierion fouses on the capability of a control center to operate certain BES Facilities, which aligns with the Transmisison Operator definition to "operate" transmisison Facilities. The Transmission Owner owns and maintains transmission Facilities by definition, and does not inherently "operate" them. Industry has created a compliance gap via the entity registration process, entities that have been registered only as TOs and operate two or more BES facilities have not been correctly registered as TOPs as well. This creates a reliability gap with PER-005-2 TO applicability and potentially other standard requirements as well.

NERC should revisit the registration process for entities that have this reliability gap rather than revise standard requirements to address a registration issue.

Likes 0	
Dislikes 0	
Response	

Matt Carden - Southern Company - Southern Company Services, Inc. - 1

Answer	
Document Name	
Comment	

Southern Company does not have any other comments to add.

Likes 0	
Dislikes 0	
Response	

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	
Document Name	
Comment	

The Redline to Last Approved and Redline to Last Posted files have editorial errors in the bullets of Criterion 2.12. The 75 MW**h** in the second bullet is missing the “h”. Additionally, there should be spaces before the “kV” for “60kV” and “300kV”.

Likes 0	
Dislikes 0	

Response

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	
Document Name	

Comment

While the background information for this posting indicates three remaining SARs will be addressed at a later date, addressing the Modifications to CIP-002 and CIP-014 SAR (submitted by the Project 2015-09 Standard Drafting Team chair) should not continue to be delayed. When initially submitted on May 26, 2021, and approved by the Standards Committee on July 21, 2021, this SAR warned of a gap relating to Transmission Planner and Planning Coordinator identification of IROLs that would open if revisions to CIP Standards CIP-002 and CIP-014 were not timely made prior to the Project 2015-09 Operations and Planning Standard revisions going into effect on April 1, 2024, and that gap has now materialized.

Likes 0	
Dislikes 0	

Response

Jeffrey Streifling - NB Power Corporation - 1

Answer	
Document Name	

Comment

While the background information for this posting indicates three remaining SARs will be addressed at a later date, addressing the Modifications to CIP-002 and CIP-014 SAR (submitted by the Project 2015-09 Standard Drafting Team chair) should not continue to be delayed. When initially submitted on May 26, 2021, and approved by the Standards Committee on July 21, 2021, this SAR warned of a gap relating to Transmission Planner and Planning Coordinator identification of IROLs that would open if revisions to CIP Standards CIP-002 and CIP-014 were not timely made prior to the Project 2015-09 Operations and Planning Standard revisions going into effect on April 1, 2024, and that gap has now materialized.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

“A group of contiguous Elements” (GCE) is described in the Technical Rationale as a concept. Given this is not a defined term in the Glossary of Terms, nor is it planned to be, can the SDT provide additional examples of a GCE and what would (or would not) qualify as a GCE under the proposed 2.12 exclusion criteria?

Provide clarity for how HVDC systems are to be considered, specifically when the HVDC local control room only control elements within the HVDC system, including HVDC station to station communiction.

Likes 0	
Dislikes 0	

Response

Hayden Maples - Hayden Maples On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Hayden Maples

Answer	
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Midwest Reliability Organization's NERC Standards Review Forum (MRO NSRF) on question 5

Likes 0	
Dislikes 0	

Response

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1

Answer	
Document Name	

Comment

NIPSCO believes that the gap that the revised Control Center definition is seeking to address is best addressed in the registration process, not in changing NERC defined terms. Additionally, NIPSCO does not believe it to be consistent with NERC's bright line criteria of 100kV for Transmission Facilities, for the SDT to add "aggregated weight values" in Attachment 1, 2.12 for line voltage that is considered Distribution

Likes 0	
Dislikes 0	

Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	
Thank you for the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	
Document Name	
Comment	
Exelon is responding in support of the EEI comments to this question.	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no additional comments.	
Likes 0	
Dislikes 0	
Response	

Dave Krueger - SERC Reliability Corporation - 10	
Answer	
Document Name	
Comment	
• SERC appreciates the ongoing efforts to refine the CIP-002 standard. SERC questions the reasoning for the newly added Exemption 4.2.3.3 which broadly excludes whole Cyber Systems within extended ESPs (that could not otherwise be excluded by the ESP exemption in 4.2.3.2). No reference to support such a broad exclusion in the field trial or in the Technical Rationale was found to address any possible reliability gaps caused. This wording also does not address the availability impacts of the loss of such Cyber Assets, which FERC has found to be material in the revisions of standards such as CIP-012.	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC has no comment.	
Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	

Comment

While the background information for this posting indicates three remaining SARs will be addressed at a later date, addressing the Modifications to CIP-002 and CIP-014 SAR (submitted by the Project 2015-09 Standard Drafting Team chair) should not continue to be delayed. When initially submitted on May 26, 2021, and approved by the Standards Committee on July 21, 2021, this SAR warned of a gap relating to Transmission Planner and Planning Coordinator identification of IROLs that would open if revisions to CIP Standards CIP-002 and CIP-014 were not timely made prior to the Project 2015-09 Operations and Planning Standard revisions going into effect on April 1, 2024, and that gap has now materialized.

Likes 0	
Dislikes 0	

Response

Hillary Creurer - Allete - Minnesota Power, Inc. - 1

Answer	
Document Name	

Comment

HVDC lines by nature of how they work demand interaction between the two ends to operate properly. However, they do not have operational control over other transmission elements. Due to how HVDC systems operate, Minnesota Power believes they should be excluded from the definition of a Control Center.

Likes 0	
Dislikes 0	

Response

Marcus Bortman - APS - Arizona Public Service Co. - 6

Answer	
Document Name	

Comment

AZPS has no additional comments at this time

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
"A group of contiguous Elements" (GCE) is described in the Technical Rationale as a concept. Given this is not a defined term in the Glossary of Terms, nor is it planned to be, can the SDT provide additional examples of a GCE and what would (or would not) qualify as a GCE under the proposed 2.12 exclusion criteria? Provide clarity for how HVDC systems are to be considered, specifically when the HVDC local control room only control elements within the HVDC system, including HVDC station to station communiction.	
Likes 0	
Dislikes 0	
Response	

Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
We appreciate the efforts of the STD on a very difficult topic. Our overall concern is that the expansion of Control Center to Transmission Owners continues to conflict with the role that TO's play in the functional operation of the BES. We recognize there are TOs which function as TOPs, or agents of TOPs, and expanding the definition of Control Centers does not really address the problems and risks that these entities represent. The exclusion criteria helps, in some cases, to limit compliance to the higher risk entities, however it also creates administrative compliance risk to the smaller agencies.	
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	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	2021-03_Unofficial_Comment_Form_08292024_EEI Final Comments.docx
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	

Emma Halilovic (via Proxy: Ijad Dewan) – Hydro One Networks, Inc. – 1

Question 1:
Answer: No

Comments: Clarity on “SCADA system that can control the transmission Facility”. The standard specifically excludes “Field Assets used for Telemetry” but does not also exclude regional data concentrators. The new verbiage only talks about the capability to control -> This needs to be quantified as available operator interfaces designed for control of these 2 or more transmission substations; not the ability to configure an interface for control. An argument can be made that a regional data concentrator "could" be used to issue controls. Although impractical for grid control, however it is possible. Hydro One suggestion is to change "capability" to "authority" in the definition on Pg.2.

Question 2:
Answer: Yes

Question 3:
Answer: No

Comments: This criterion should be clearer to identify the associated Transmission BES Cyber System and not the physical Control Center. There are many utilities that operate a Transmission and Distribution function out of the same control center. This would be a good opportunity to Clearly articulate the difference between Control Center as a place (physical location) and a device (BES Cyber System controlling the BES as per the definition).

Question 4:
Answer: No

Comments: Hydro One’s opinion is that 24 months is not sufficient to implement the changes required to all regional data concentrators in service, if classified as Medium Impact BCS associated with control center, as per the revised Control Center definition.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Response to Comments

Project 2021-03 CIP-002

November 2024

RELIABILITY | RESILIENCE | SECURITY




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Table of Contents

Introduction

NERC Project 2021-03 proposes revisions to the Control Center definition and CIP-002-8 Criterion 2.12 in Attachment 1. CIP-002-8 provides "bright-line" criteria for applicable Responsible Entities to categorize their Bulk Electric Systems (BES) Cyber Systems based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the BES. The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers (TOCCs) performing the functional obligations of a Transmission Operator (TOP), specifically those that meet medium impact criteria, and clarify the language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.

There were 63 sets of responses, including comments from approximately 165 different people from approximately 105 companies representing 10 of the industry Segments.

Additional information is available on the project page.

Background

Based on industry feedback, the drafting team (DT) modified the Control Center definition along with CIP-002-8. Please refer to the CIP-002-8 Technical Rationale document 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, Dominique Love (Dominique.love@nerc.net).

Thank You

The drafting team thanks industry for your time in reviewing the proposed CIP-002-8 standard and providing comments and proposals for the DT's consideration. All comments received have been reviewed and discussed. Response to comments have been drafted in a summary response.

Control Center Definition

Currently approved definition:

> ***Control Center -*** *One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.*

Draft 1[1] proposed definition:

> ***Control Center -*** *One or more rooms where a responsible entity hosts operating personnel to monitor and control the Bulk Electric System (BES) in real-time, as described below, including any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time. Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units.*
>
> 1. *Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;*
> 2. *Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;*
> 3. *Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations;*
> 4. *Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or*
> 5. *Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more locations in real-time.*

Draft 2[2] proposed definition:

> ***Control Center -*** *One or more facilities used by the operating personnel described below to monitor and control the Bulk Electric System (BES) in real-time, and any facilities that contain the Cyber Assets required for operating personnel to monitor and control the BES in real-time. Field assets, such as remote terminal units and data aggregators, are excluded from the scope of the Control Center definition.*
>
> 1. *Reliability Coordinator personnel who perform the BES company-specific Real-time reliability-related tasks of a Reliability Coordinator;*
> 2. *Balancing Authority personnel who perform the BES company-specific Real-time reliability-related tasks of a Balancing Authority;*
> 3. *Transmission Operator personnel who perform the BES company-specific Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more locations;*
> 4. *Transmission Owner personnel who have the capability to control Transmission Facilities at two or more locations using Supervisory control and Data Acquisition (SCADA); or*
> 5. *Generator Operator personnel who perform the reliability tasks of a Generator Operator for generation Facilities at two or more locations.*

[1] Posted for comment and ballot period September 26 – November 9,2023

[2] Posted for comment and ballot period April 2 – May 16, 2024

Draft 3[3] proposed definition:

> ***Control Center*** *- One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.*
>
> *OR*
>
> *One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers and excluding field Cyber Assets used for telemetry.*

Bulk Electric System (BES) Reference for Transmission Owner

- Suggest updating to "One or more facilities of a Transmission Owner that have the capability **to control the Bulk Electric System and** to control Transmission Facilities at two or more locations in real-time using SCADA, including their associated data centers, and excluding field Cyber Assets used for telemetry."
- "One or more facilities of a Transmission Owner that have the capability to control **BES** Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry."

DT Response

The concept of BES is already captured in the definition of Facility, defined in the NERC Glossary of Terms as "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt capacitor, transformer, etc.). The DT believes that expanding to BES Elements beyond "transmission Facilities", as contemplated per the proposed language 'to control the BES and to control Transmission Facilities', will inappropriately widen the scope and introduce ambiguity. The DT also believes that it is important to retain the term "transmission" to avoid unintended inclusion of other asset types such as distribution or generation assets.

Mirror 'facilities hosting operating personnel' for Transmission Owner

- Disagreement with the change from "facilities hosting operating personnel" [for TO] to "facilities having the capability to control transmission Facilities". The proposed language is inappropriately over-broad and has the potential to errantly identify Transmission Facilities as Control Centers, a function they were never intended to execute. If the TO does not have to have operating personnel hosted in a location (that allows for the control of two or more BES transmission Facilities), are they held to a higher standard than the RC, TOP, and BA entities? The RC, TOP and BA entities are clearly required to be hosting operating personnel according to their applicability in the definition.
- As an example, where an unmanned substation has control of local transmission switching for two different switchyards. Operating personnel are not hosted in the location, but SCADA controls allow for the control of two or more transmission Facilities. The proposed definition identifies this as a Control Room. The fact may be that the two local transmission Facilities are within the same fencing and at the same physical location. Is the intent of the drafting team to define these as control centers?
- Request to exclude 'regional data concentrators' by ensuring that the 'capability to control' is limited to locations where there is an available operator interface designed for control (not for the ability to configure an interface for control)

[3] Posted for comment and ballot period August 29 – October 15, 2024

DT Response

The DT in previous unsuccessful ballots has attempted to clarify the location of the Control Center and its personnel and associated data centers. The industry was clear that it wanted the Control Center definition language for the RC, BA, TOP, and GOP to revert back to the existing Control Center definition, which was done in the recent successful ballot.

The new language in the Control Center definition that specifically applies to the TO is focused on the existence of SCADA (Cyber Assets) that can remotely operate BES Facilities with or without the existence of operating personnel at the Control Center location. The TO's TOP could have access to operate the TO BES Cyber Assets via the TO's SCADA. The important issue is the identification and cyber protection of the TO's SCADA system at the appropriate impact level based on span of control.

A Control Center is a place where, in the normal course of business, management of the BES occurs. Human Machine Interface (HMI) at transmission stations with the capability to monitor and control should not be pulled in. While these systems may be used for local actions, they don't typically have ties back into the larger centralized system. Cyber Assets and HMI at transmission stations with the capability to monitor and control locally should be evaluated based on their location and should have the associated impact level established under CIP-002 Attachment 1.

Early in the project, the DT attempted to define "data concentrators," but could not reach industry consensus. In the Control Center definition, field Cyber Assets. such as some data concentrators or data aggregators, are excluded from the definition. Registered Entities are responsible for reviewing the capabilities of their data concentrators and data aggregators to determine if they are associated with a Control Center or with another type of asset (e.g., station for which it is aggregating data). Data concentrators should then be evaluated based on their location and have the associated impact level established under CIP-002 Attachment 1.

Based on industry support for this version of Control Center definition, the DT has elected not to make any changes.

Word Selection

- Change "capability" to "authority", or otherwise strike "capability" from the definition
- Recommendation to replace "facilities" with alternate such as "locations" or sites"
- Concerns raised that a lack of specificity regarding the entity that is responsible to determine what equipment is included in a transmission Facility will lead to inconsistencies in application and enforcement
    - Proposed language: "One or more Transmission Owner facilities, including their associated data centers, and excluding field Cyber Assets used for telemetry, that have the capability in real-time using Supervisory Control and Data Acquisition (SCADA) and host the SCADA, to control multiple transmission Facilities at two or more locations, with the equipment that compromise the transmission Facility being defined by the Transmission Owner."
- Statement that there are specific network architecture scenarios that are not limited to "facilities"
- Replace Cyber Asset with BCS

DT Response

One of the primary objectives of the DT has been to ensure that entities correctly identify Transmission Owner Control Centers (TOCC) and clarify applicability of requirements in CIP-002 such that TOCC are appropriately protected, particularly if the TO has the capability to operate transmission Facilities. The DT recognized during the Field Test that some TOs incorrectly believe that the lack of authority to operate BES Facilities means that they do not have a Control Center. However, entities that lack the authority to operate BES Facilities may still have the capability to do so. The cyber security risk that must be protected is access to the BES Cyber Asset, i.e., the SCADA system that can control the Facility. For this reason, the DT believes that capability is the correct term to use in the Control Center definition.

The DT explored various alternatives to the lower-case term ‘facilities’ during the drafting process and was unable to agree on a term that appropriately conveyed the variety of configurations that may be present across the industry. After iterating through some more expansive modifications to the Control Center definition, the DT ultimately reverted to the current Control Center definition language as it applies to the RC, BA, TOP, and GOP, including use of the lower-case term ‘facilities’. The current definition includes both lower-case ‘facilities’ and upper-case ‘Facilities’. The DT has received feedback from industry that the distinction between the two terms has been well-established over time and that further clarification is not necessary. With respect to specific network architecture scenarios that are not adequately covered by the existing language, the DT believes that the work needed to resolve these additional challenges that have been raised by the industry extends beyond the scope of the portion of the 2016-02 SAR that was assigned to the 2021-03 DT. Based on industry support for this version of the Control Center definition, the DT has elected not to make any changes.

The DT considered the recommendation to replace ‘Cyber Asset’ with ‘BES Cyber System’ in the language that excludes field Cyber Assets used for telemetry; however, the DT recognizes that Cyber Assets are a subset of BES Cyber Systems and believes that it is more appropriate to be comprehensive in the exclusion.

Structure

- The formatting of the revised Control Center definition is confusing where it uses the term “OR”. Use of all upper-case letters within NERC Standards has generally implied use of an abbreviation.
- Recommend replacing this term with “or” and reformatting the definition to prevent the use of a second paragraph solely to include TO facilities.

DT Response

The revised Control Center definition is intentionally split into two sentences separated by “OR” to logically separate the TOCC from the other Control Center types. The logical interpretation is that one or the other applies. Each entity is responsible for considering both sentences, as appropriate for their registrations, and identifying the appropriate Facilities. The DT is not aware of any acronym “OR” in the NERC Glossary of Terms, or future use of the term/acronym “OR”, that would create confusion.

Utilization of the NERC-Defined Term SCADA

- Recommend to eliminate reference to “SCADA” as it is too prescriptive on technology. SCADA is one method used to operate elements at BES Facilities; however, there are other technologies such as a relay network or other industrialized control system not defined as SCADA [terminal servers, remote management protocols to HMIs, or other similar modern means for remote control].
- Limiting inclusion to only those TO facilities using SCADA protocols for control may introduce a reliability gap where such control is affected using terminal servers, remote management protocols to HMIs, or other similar modern means for remote control. A suggestion may be to review the changes made in CIP-005-6 and CIP-005-7 to describe ‘system-to-system’ relationships between Cyber Assets, which is protocol agnostic and provides some future growth room without requiring standards modification.

DT Response

The term SCADA is defined in the NERC Glossary of Terms as ‘A system of remote control and telemetry used to monitor and control the transmission system’. The DT intentionally used the industry terminology SCADA to avoid technologies in relay networks and access mechanisms. The use of the NERC defined term “SCADA” is intended to exclude Cyber Assets used at a relay maintenance office to change relays setting, which may allow the capability to remotely operate a breaker. These Cyber Assets would not be considered a Control Center, but may be required to be protected under other cyber security categories. Based on industry support for this version of Control Center definition, the DT has elected not to make any changes.

Application to HVDC Stations

- Recommendation to expand exclusion verbiage to include HVDC stations
  - Specific language: "excludes station to station communication for HVDC control functions"
  - One commenter asserts that HVDC systems do not have operational control over other transmission elements.
- Clarification requested to differentiate between local and remote control, with proposal as follows:
  - One or more facilities of a Transmission Owner that have **Cyber Assets with** the capability to **remotely** control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry **and station to station communication for HVDC control functions**.
- Clarity requested for how HVDC systems are to be considered, specifically when the HVDC local control room only control elements within the HVDC system, including HVDC station to station communication.

DT Response

The station-to-station communication for HVDC control functions may be eligible for exemption under CIP-002-7 Section 4.2.3.3. This version has been filed with FERC and awaiting their approval.

Transmission Owners who have facilities that are capable of controlling High Voltage Direct Current (HVDC) Facilities, each Responsible Entity will need to engage with their Regional Entity in order to determine how the language "transmission Facilities at two or more locations" should be applied based on the specific configuration. The current definition has not changed for Transmission Operators, and thus there is no expected change in applicability to classification of their operated HVDC Facilities. Based on industry support for this version of Control Center definition, the DT has elected not to make any changes.

Clarity on use of term "Facilities"

- The definition as proposed is unclear regarding the number of Facilities at another location that must be controlled in order to be considered a Control Center. Suggestion to revise the Control Center definition to be consistent with the examples provided in the Technical Rationale, which clarifies that there must be control of at least two Facilities at another distinct location to be considered a Control Center.

DT Response

When considering the language "transmission Facilities at two or more locations" and "generation Facilities at two or more locations," it is generally expected that the Facilities will have separate street addresses. Facilities located at a single street address would be associated with a single location. An entity must have more than one Facility and must have Facilities at two or more locations in order to have "transmission Facilities at two or more locations" or "generation Facilities at two or more locations." The DT believes that the existing examples provided in the technical rationale are adequate and that no language changes are necessary to the Control Center definition.

Registration Process

- The gap that the Control Center definition revision is addressing would be best addressed by NERC in the registration process and not in the modification of the defined term.

- Concern that the expansion of Control Center to Transmission Owners continues to conflict with the role that TO's play in the functional operation of the BES. While there are TOs which function as TOPs, or agents of TOPs, expanding the definition of Control Centers does not really address the problems and risks that these entities represent.

DT Response

The DT feels that it has addressed the gap within the Control Center definition regarding Transmission Owners, as provided for in the scope of the related SAR for this project. The DT has worked to keep the scope of the changes as narrow as possible to avoid creating any unnecessary burden on Transmission Owners. The DT believes that appropriately classifying the Transmission Owner facilities as a Control Center is adequate to address the identified risks to the BES created if those facilities with the capability to control are not adequately protected. These facilities will have the same requirements as a similarly situated Transmission Operator. In addition, the NERC registration process is outside this DT's SAR scope and purview pursuant to the NERC Rules of Procedure.

Field Cyber Assets

- Field Cyber Assets are collectively the 'eyes and ears' of the Control Center for providing the decisional data and wide-area situational awareness, and the broad loss of field telemetry systems has been implicated in causing the inoperability of Control Centers in past NERC Lessons Learned documents. Only considering the impact of singular telemetry devices on the field location they are located at would seem to overly credit the redundancy of having many telemetry devices at the expense of providing CIP protection for any of them, instead of considering them as part of the systems which provide critical data for the Control Center to perform its reliability. If the SDT wishes to address the recently added SAR by suggesting complete removal of these devices from CIP consideration, perhaps an additional field trial or data gathering would provide such support. Even without such global removal language, an entity could provide evidence that the loss, degradation, or misuse such telemetry Cyber Systems do not impact the reliability tasks that they specifically perform if that was the case.

DT Response

In previous unsuccessful ballots, the DT attempted to clarify the electronic remote control of transmission Facilities. In the recent successful ballot, the DT instead used the NERC defined term SCADA, but excluded field Cyber Assets from being considered based on input from industry. The underlying premise is that field Cyber Assets will be evaluated and have the associated impact level established under CIP-002 Attachment 1. Field Cyber Assets will be evaluated along with other asset types (e.g., substation, IROL, etc.) that are subject to CIP-002-8 and would be protected as such. Thus, exclusion from the Control Center definition does not mean that the telemetry goes unprotected. If the field Cyber Assets used for telemetry are incorporated into the Control Center, then the Control Center extends into all of the field Cyber Assets that send information to the Control Center. Thus, everything is high which isn't appropriate from a risk perspective.

Based on industry support for this version of Control Center definition, the DT has elected not to make any changes.

Incorporating 'reliability tasks' in 1.3 for Transmission Operator and/or Transmission Owner

- Suggest splitting out part 1.3 in Attachment 1 IRC for TOP and TO, as TOP should have similar wording as per the Control Center definition to the RC, BA, and GOP and the TO should be exclusive to part 1.3 wording.
- Recommended that "reliability tasks" be included in the High Impact Rating Criteria 1.3. for Transmission Operators (TOPs) and Transmission Owners (TOs). The "functional obligations" language in CIP-002-5.1a, Attachment 1, 1.3. for the TOP was removed, but not replaced with "reliability tasks".

DT Response

The DT holds that the distinction between the TO and TOP Control Centers does not carry into the categorization assessment process of Attachment 1 of CIP-002-8. After the TOP or TO has identified a Control Center, the application of part 1.3 has no separate unique application to the TO apart from the TOP registrations. Further, "reliability tasks" have no bearing once the TOP or TO have identified their respective Control Centers as they both have the capability to control transmission Facilities. Inclusion of "reliability tasks" in criterion 1.3 could continue to create confusion over the distinction between the capability to control versus the authority to control. Based on industry support for this version of Control Center definition, the DT has elected not to make any changes.

Clarity regarding 'reliability tasks' language across registered entities

- References to "reliability tasks" should align with NERC standard PER-005-2 language and be referred to as "BES company specific Real-time reliability related tasks" to lessen the opportunity for confusion, auditor interpretation, and reliability gaps.
- The language "perform the reliability tasks" is included for the RC, the BA and the GOP. PER-005-2 does not include a requirement for the GOP to *"create a list of BES company-specific Real-time reliability-related tasks" (reliability tasks list)*.
- Since 'reliability tasks' is not a defined term, it will be ambiguous without proper expansion within guidelines and technical basis or some other form of guidance.
- It is still not clear in the plain language of the requirement where the 'reliability tasks' of each Responsible Entity are to be derived. To establish a clear linkage for this undefined phrase, perhaps clearly stating that if a task-based responsibility exists in another NERC Reliability Standard, that constitutes a reliability task which bears accounting for in CIP-002-8. Past usage of undefined or non-specific vestigial terminology in CIP-002-5 has led to misunderstanding and inconsistent interpretations.
- The term "reliability tasks" adds no additional clarity. Many transmission owners only manage maintenance, and not operations of their systems. The problem is rooted in the registration where, if an entity does perform TOP reliability tasks, the CEA should force them to be properly registered as a TOP. The Drafting Team has limited ability to address this issue, however, the Drafting Team should recommend that the NERC Functional Model be resurrected and brought up to current industry practices as part of this project.

DT Response

The replacement of 'functional obligations' with 'reliability tasks' was incorporated given that the NERC Functional Model is no longer being actively maintained and to align with the language used in the current Control Center definition. Usage of 'reliability task" is to provide flexibility to an entity when referring to activities performed by that entity to ensure resource adequacy and operational reliability of BES Elements and Facilities. Additional information on the BES reliability operating services that may be useful to entities when they are defining their reliability tasks can be found in the technical rationale document associated with CIP-002-7. Each entity is ultimately responsible for reviewing their obligations under the NERC Standards to identify their reliability tasks. Based on industry support for this version of Control Center definition, the DT has elected not to make any changes.

The DT feels that updating the term “reliability tasks” is outside the scope of the related SAR for this project. The DT does agree that proposed changes to registration classifications and reactivating the NERC Functional Model can be separately discussed with and reviewed by NERC. However, the DT does not feel it is in its purview to make changes.

Separately identify the physical location of a Control Center from the activities performed

- The criteria should be clearer to identify the associated Transmission BES Cyber System and not the physical Control Center. They note that there are many utilities that operate a Transmission and Distribution function out of the same control center. They request that the Drafting Team clearly articulate the difference between Control Center as a place (physical location) and a device (BES Cyber System controlling the BES as per the definition).

DT Response

The changes and language used allow flexibility for entities to define (using the Attachment 1 criteria) the categorization of their specific cyber systems and Cyber Assets, and their associated impact rating. Per the current criteria, an entity defines the impact rating of the BES Cyber System based on its impact to the BES. The flexibility allows entities to develop processes which address the risks posed to the BES by their specific Elements, Facilities, and systems.

In addition, the scope of this DT’s SAR prohibits the expansion of revising the existing standards to address specific BES Control Center functions or technologies beyond the TOCC. The DT does recognize the need to further address technologies and architectures (cloud, virtual Control Centers, AI, etc.) which may patently change the requirements, categorization, and risk posed to an entity and BES at large. A separate SAR would be required to holistically review and revise the Control Center definition to an alternate approach that distinguishes between the physical location of the Control Center and the BES Cyber Systems that provide Control Center functionality.

Editorial Recommendations for Accuracy/Clarity

- A commenter notes the Redline to Last Approved and Redline to Last Posted files have editorial errors in the bullets of Criterion 2.12. The 75 MWh in the second bullet is missing the “h”. Additionally, there should be spaces before the “kV” for “60kV” and “300kV”.
- Another commentor suggests replacing suggests replacing ‘The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per BES Transmission Line” that is monitored and controlled by the Control Center or backup Control Center shown in the table below.’ With ‘The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per BES Transmission Line” shown in the table below, for lines that are monitored and controlled by the Control Center or backup Control Center.’

DT Response

The DT appreciates the diligent red-line review performed and will make the necessary corrections prior to the final posting. Also, the DT has reviewed the recommendation to replace ‘The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per BES Transmission Line” that is monitored and controlled by the Control Center or backup Control Center shown in the table below.’ The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per BES Transmission Line” shown in the table below, for lines that are monitored and controlled by the Control Center or backup Control Center.’ The DT believes this to be a non-substantive change that will help readability while not changing the scope, applicability, intent of the document, or the actions required by affected entities. This change will be incorporated into the final posting.

BES Risk Cannot be Quantified by Counting Lines Operated

- The risk to the BCS at a Control Center to the reliable operation of the BES is not easily covered by counting the quantity of transmission lines operated. Two Control Centers operating the same number of transmission lines may pose very different risks to the BES. For example, if one Control Center is predominantly operating Transmission lines at substations interconnected with Generation Facilities it may pose more risk than a Control Center operating Transmission lines at substations that are not interconnected with Generation Facilities. They propose the following language for criterion 2.12: Each Control Center or backup Control Center operated by a Transmission Operator or owned by a Transmission Owner.

DT Response

The Field Test has confirmed the existence of TO and TOP small entities' control areas that do not have a significant impact on BES reliability, some of which include interconnected generation. The current enforced language of CIP-002-5.1a is not commensurate with the risk to the BES as applied to smaller entities. The DT has provided updated language that addresses the objectives of the SAR to resolve this issue. Further, Attachment 1 of CIP-002 includes additional criteria that are intended to identify more impactful risks associated with assets, including criterion 2.8 that specifically includes Transmission Facilities providing the generation interconnection required to connect generator output to the Transmission System that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3. Criterion 1.3 appropriately elevates the BES Cyber Systems located at TO and TOP Control Centers for these assets to High Impact.

Applicability of Criterion 2.12 to the Transmission Owner

- A commentor questions why criterion 2.12 is applicable to Transmission Owners rather than just Transmission Operators and notes that "the criterion focuses on the capability of a control center to operate certain BES Facilities, which aligns with the Transmission Operator definition to "operate" transmission Facilities. The Transmission Owner owns and maintains transmission Facilities by definition and does not inherently "operate" them."

DT Response

The DT does not agree with the premise that Transmission Owners do not operate transmission Facilities. The Field Test identified the existence of TOs that have SCADA systems that are used by their personnel to operate transmission Facilities under Operating Instructions from the TOP, or under prior approved protocols to independently operate in emergency conditions. As such, a TO with the capability to control may have a Control Center that needs to be evaluated under criterion 2.12. If a TO does not have a SCADA system and provides Operating Instructions via radio or phone to field personnel to operate transmission Facilities, then the TO does not have a Control Center and is not subject to criterion 2.12 based on the revised Control Center definition.

Non-BES Assets in Criterion 2.12

- Recommendation to add a paragraph or bullet to the Exclusion section of criterion 2.12 to clarify that facilities with an approved BES Exception (or exclusion) for certain facilities may be excluded from the calculation of the aggregate weighted value.
- Transmission lines operated at <100kV are not part of the BES and should not be included in the aggregate weighted value model.

DT Response

The DT recognizes that there is an established process, as documented in Appendix 5C of the NERC Rules of Procedure, that allows entities to request an exception from the application of the NERC definition of Bulk Electric System. An exception may be granted that will have the effect of either including within the BES an Element or Elements that would otherwise be excluded by application of the BES Definition or excluding from the BES an Element or Elements that would otherwise be included by application of the BES Definition.

The table provided in criterion 2.12 specifies that only a “BES Transmission Line” receive a weighted value. Therefore, the DT does not believe that additional language is needed to clarify that non-BES elements may be excluded from the calculation of the aggregate weighted value.

Further, the DT believes that the specific reference to the “BES Transmission Line” in the table makes it adequately clear that it is only a subset of lines below 100kV that are to be considered. Any non-BES Transmission Lines would not be included in the aggregate weighted value calculation. Additional details regarding the inclusion of lines <100kV in the Aggregate Weighted Value calculation can be found in the Technical Rationale.

Criterion 2.12 Table

- There is a gap between the X99 and Y00 “Characteristics of Line” levels. For example, a 199.5kV line is not rated on this table.
- Request explicit explanation in the Standard of the weighted value of zero for “Each BES Transmission Line 500 kV and above.”

DT Response

Regarding the application of the table provided to a line that is nominally rated at 199.5kV, the DT believes this to be more of a theoretical concern than a practical concern. The DT has constructed the table similarly to the corresponding table that applies to Transmission Facilities. The DT is not aware of any significant challenges in interpreting the existing table and believes that deviating from the established structure would create unnecessary confusion.

With respect to the content of the table for BES Transmission Lines 500kV and above, the DT believes that it is appropriate to use “0 (N/A)”. The “(N/A)” has also been added to the corresponding table in criterion 2.5 that applies to Transmission Facilities. No weight is needed for BES Transmission Lines 500kV and above, because criterion 1.3 elevates the BES Cyber Assets used by and located at a Control Center that monitors and controls Transmission Facilities operated at 500kV or higher to high impact.

Criterion 2.12 Exclusion Clause

- Language in the exemption appears to allow for the exclusion of a Control Center if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines.

- Use of 75 MWh gross export is problematic and will lead to gaming. There is no precedent for using a MWh value. Instead, the Drafting Team should consider the maximum line rating, since this allows for any situation where power flows may change.
- Request that the Drafting Team provide additional examples of a GCE and what would or would not qualify as a GCE under the proposed 2.12 exclusion criterion.

DT Response

The DT provided flexibility in the language to allow entities to develop processes which include or exclude Elements, Facilities, and/or systems based on their specific risk to the BES. As written, the exclusion language does not allow for exclusion of a Control Center. Rather, an entity may use the exclusion clause to eliminate specifically defined transmission Lines from their recalculated aggregate weighted value, provided they are able to meet and demonstrate adherence to the 'group of contiguous Elements, (GCE) requirements. Further, the DT has included limits on entities that may pursue an exclusion by limiting those who are eligible to entities with an unadjusted "aggregate weighted value" of less than 12000 and by limiting the gross export of a GCE to 75 MWh. These limits are intended to prevent application of the exclusion to large control areas and to differentiate between non-impactful load serving areas and areas that are more likely to have an impact on the interconnected BES.

Regarding the use of MWh units, as opposed to MW or MVA line capability, the DT originally proposed a 75 MW threshold and determined that it wasn't an appropriate unit to represent power flow over time. The DT doesn't believe that an MVA line rating would be appropriate because it doesn't directly correlate to actual power flow and the resulting impact to the BES if Elements are compromised. Entities will be responsible for providing evidence that they have remained below the 75 MWh threshold to prevent gaming.

Based on industry support for this version of Control Center definition, the DT has elected not to make any changes.

The DT has provided an example GCE in the technical rationale to provide general guidance to the criterion 2.12 Exclusion Clause. Further, criterion 2.12 examples 3 and 4 in the technical rationale include additional detail about how an entity might apply the GCE exclusion. An entity may choose for themselves whether or not to pursue an exclusion under the documented exclusion clause. With respect to an entity's use of the exclusion clause, it is the entity's responsibility to determine the most appropriate method to demonstrate their compliance and to retain the evidence necessary.

Implementation Plan

- A commentor expressed concern that if HVDC control functions are considered in scope as a Control Center, additional time would be necessary to meet additional requirements.
- A commentor expressed concern that there is uncertainty in the standard or Implementation Plan on the timeline for an entity who exceeds the 75MWH exclusion threshold to recalculate their CIP-002-8 inclusions. They suggest including a specific example in the Implementation Plan to address this occurrence to reduce ambiguity.
- The 12-month period makes it unclear how new transmission lines are handled even if it is known that they will increase the net export beyond the 75MW threshold. Commentors request clarity on when exceeding the threshold is a planned change, vs an unplanned change and whether an entity could lose the exemption, and then gain it back before the 2-year implementation period is over.
- The proposed 24-month implementation plan has the potential to become very limiting for large entities that could have a large number of new Facilities and facilities due to the current revision of the standard. Recommend additional time of 6-12 months to account for updating tools and models in use for the

current version of the standard and to allow for changes due to standard effectiveness occurring in the middle of a calendar year.

DT Response

Transmission Owners who have facilities that are capable of controlling High Voltage Direct Current (HVDC) Facilities, each Responsible Entity will need to engage with their Regional Entity in order to determine how the language “transmission Facilities at two or more locations” should be applied based on the specific configuration. The current definition has not changed for Transmission Operators, and thus there is no expected change in applicability to classification of their operated HVDC Facilities. Given that the earliest effective date of CIP-002-8 is April 1, 2026 (aligning with the earliest possible effective date of CIP-002-7), the DT believes that entities will have adequate time to evaluate impacts before the 24-month window commences and that no modifications to the Implementation Plan are needed.

Each entity must establish their own process to meet the annual periodicity requirements of CIP-002 and is responsible for setting the periodicity of when they will evaluate for the 75 MWh threshold. The entity must respect their established process, which may prevent the entity from pursuing an exclusion for any transmission Lines per criterion 2.12. The DT does not believe that it is appropriate to create a formal example since it would be subjective and specific to each entity’s process. The criterion 2.12 language and the implementation plan make it clear that the evaluation of the exclusion must be performed annually and coordinated with an entity’s annual CIP-002 review. When considering planned changes, entities should consider the intent of the standard and utilize the exclusion as deemed appropriate. The “Planned or Unplanned Changes” section of the implementation plan governs the amount of time that an entity has to move to the appropriate level of protection.

The DT considered increasing the phased-in implementation date for CIP-002-8, Requirement R1, Attachment 1 criterion 2.12 from 24 months; however, the DT elected to retain a 24-month window as it aligns with the established 24-month window that is currently provided to Responsible Entities who identify their first high impact or medium impact BES Cyber System. The DT does not see the justification for extending the implementation window. Further, given that the earliest effective date of CIP-002-8 is April 1, 2026 (aligning with the earliest possible effective date of CIP-002-7), entities will have adequate time to evaluate impacts before the 24-month window commences.

Perceived Gaps

- A commenter expressed concern with the exemption in 4.2.3.3 and requests rationale on why the drafting team included this exemption.
- Several commenters assert that a gap relating to Transmission Planner and Planning Coordinator identification of IROLs will now materialize as, the Modifications to CIP-002 and CIP-014 portion of Project 2021-03 has not completed prior to the Project 2015-09 revisions went into effect. These commenters request that this project work is not delayed any further.

DT Response

Exemption 4.2.3.3 was added as part of the 2016-02 DT efforts and is part of the NERC Board approved CIP-002-7.

The DT recognizes the concerns related to IROLs and appreciates it being presented. The TOCC portion of Project 2021-03 was assigned as high priority by the Standards Committee (SC). Because of this, and the DT’s recognition that combining both the TOCC and IROL portions together could cause delay in its approval, the DT’s focus was to complete the revisions to the TOCC portion first. Once the TOCC revisions pass final ballot, the DT will then begin to focus its work on the portion of Project 2021-03 addressing the IROL language of CIP-002 and CIP-014.

Reminder

Standards Announcement

Project 2021-03 CIP-002

Additional Ballot and Non-binding Poll Open through October 15, 2024

Now Available

An additional ballot for **draft three of CIP-002-8 — Cyber Security - BES Cyber System Categorization** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels are open through **8 p.m. Eastern, Tuesday, October 15, 2024**.

Based on recent board adopted standard CIP-002-7, the posted version for 2021-03 CIP-002 reflects CIP-002-8. The Standards Balloting and Commenting System (SBS) does not allow edits once a ballot is created and/or opened. Even though the standard versioning within the SBS states CIP-002-Y, the version number within this posting is correct and entities will be voting on CIP-002-8.

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 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 2021-03 CIP-002" in the Description Box.

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NERC
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Standards Announcement

Project 2021-03 CIP-002

Formal Comment Period Open through October 15, 2024

Now Available

A formal comment period for **draft three of CIP-002-8 — Cyber Security - BES Cyber System Categorization**, is open through **8 p.m. Eastern, Tuesday, October 15, 2024**.

Based on recent board adopted standard CIP-002-7, the posted version for 2021-03 CIP-002 reflects CIP-002-8. The Standards Balloting and Commenting System (SBS) does not allow edits once a ballot is created and/or opened. Even though the standard versioning in the SBS states CIP-002-Y, the version number within this posting is correct and entities will be voting on CIP-002-8.

The drafting team's considerations of the responses received from the previous comment period are reflected in this draft of the standard.

Commenting

Use the 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.

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- *Passwords expire every **6 months** and must be reset.*
- *The SBS **is not** supported for use on mobile devices.*
- *Please be mindful of ballot and comment period closing dates. We ask to **allow at least 48 hours** for NERC support staff to assist with inquiries. Therefore, it is recommended that users try logging into their SBS accounts **prior to the last day** of a comment/ballot period.*

Next Steps

Additional ballots for the standard and implementation plan, as well as a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 4-15, 2024**.

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

For more information or assistance, contact 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 2021-03 CIP-002" in the Description Box.

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/348)
Ballot Name: 2021-03 CIP-002 CIP-002-Y AB 3 ST
Voting Start Date: 10/4/2024 12:01:00 AM
Voting End Date: 10/15/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 264
Total Ballot Pool: 297
Quorum: 88.89
Quorum Established Date: 10/15/2024 2:37:51 PM
Weighted Segment Value: 83.05

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	84	1	50	0.735	18	0.265	0	9	7
Segment: 2	7	0.1	1	0.1	0	0	0	5	1
Segment: 3	69	1	46	0.793	12	0.207	0	6	5
Segment: 4	15	1	11	1	0	0	0	2	2
Segment: 5	73	1	45	0.804	11	0.196	0	6	11
Segment: 6	44	1	29	0.853	5	0.147	0	3	7
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	5	0.3	2	0.2	1	0.1	0	2	0
Totals:	297	5.4	184	4.485	47	0.915	0	33	33

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke	LaTroy Brumfield	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	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	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		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	City of College Station	Stacy Engelmann		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	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	Theresa Ciancio		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Negative	Comments Submitted
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Third-Party Comments
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Abstain	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	MEAG Power	David Weekley	Rebika Yitna	Negative	Comments Submitted
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Third-Party Comments
1	National Grid USA	Michael Jones		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	Third-Party Comments
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		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		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 Pend Oreille County	Angela Hall		None	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	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	U.S. Bureau of Reclamation	Richard Jackson		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		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Abstain	N/A
2	ISO New England, Inc.	John Pearson	John Galloway	Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		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	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Negative	Comments Submitted
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		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Third-Party Comments
3	Northern California Power Agency	Michael Whitney	Mason Jones	Affirmative	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	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	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	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	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	Third-Party Comments
3	Silicon Valley Power - City of Santa Clara	VAL GUZMAN		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		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Abstain	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		Abstain	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		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Acciona Energy North America	Truong Le		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith	Brandon Smith	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar	Marie Potter	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	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	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	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	Comments Submitted
5	Muscatine Power and Water	Chance Back		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	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	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Michael Johnson	Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	Comments Submitted
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Clay Walker	Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler	Qinling Zheng	Affirmative	N/A
6	Constellation	Kimberly Turco	Marie Potter	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	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	Great River Energy	Brian Meloy		None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		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	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		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	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Xcel Energy, Inc.	Steve Szablya		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	SERC Reliability Corporation	Dave Krueger		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Negative	Comments Submitted
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

Showing 1 to 297 of 297 entries

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BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/348)
Ballot Name: 2021-03 CIP-002 Implementation Plan AB 3 OT
Voting Start Date: 10/4/2024 12:01:00 AM
Voting End Date: 10/15/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 256
Total Ballot Pool: 290
Quorum: 88.28
Quorum Established Date: 10/15/2024 2:38:27 PM
Weighted Segment Value: 89.07

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	82	1	55	0.833	11	0.167	0	9	7
Segment: 2	7	0.1	1	0.1	0	0	0	5	1
Segment: 3	67	1	49	0.875	7	0.125	0	6	5
Segment: 4	15	1	10	1	0	0	0	2	3
Segment: 5	72	1	44	0.83	9	0.17	0	7	12
Segment: 6	43	1	30	0.882	4	0.118	0	3	6
Segment: 7	0	0	0	0	0	0	0	0	0
Segment: 8	0	0	0	0	0	0	0	0	0

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 9	0	0	0	0	0	0	0	0	0
Segment: 10	4	0.2	2	0.2	0	0	0	2	0
Totals:	290	5.3	191	4.721	31	0.579	0	34	34

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		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	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	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		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	City of College Station	Stacy Engelmann		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	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	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Third-Party Comments
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Negative	Comments Submitted
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		None	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Negative	Comments Submitted
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		Negative	Third-Party Comments
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Third-Party Comments
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	Comments Submitted
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Affirmative	N/A
1	OGE Energy - Oklahoma Gas and Electric Co.	Terri Pyle		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Third-Party Comments
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		Affirmative	N/A
1	PPL Electric Utilities Corporation	Michelle McCartney Longo		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	PSEG - Public Service Electric and Gas Co.	Karen Arnold		Affirmative	N/A
1	Public Utility District No. 1 of Pend Oreille County	Angela Hall		None	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	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	Comments Submitted
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	California ISO	Darcy O'Connell		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Abstain	N/A
2	ISO New England, Inc.	John Pearson	John Galloway	Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		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	Great River Energy	Michael Brytowski		Negative	Third-Party Comments
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
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		Affirmative	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		Negative	Comments Submitted
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		Negative	Third-Party Comments
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Negative	Third-Party Comments
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	Affirmative	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	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Platte River Power Authority	Richard Kiess		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	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	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	Comments Submitted
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Abstain	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		None	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		Abstain	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		None	N/A
5	Acciona Energy North America	Truong Le		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	APS - Arizona Public Service Co.	Andrew Smith	Brandon Smith	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar	Marie Potter	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	N/A
5	Entergy - Entergy Services, Inc.	Gail Golden		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Evergy	Jeremy Harris	Hayden Maples	Affirmative	N/A
5	FirstEnergy - FirstEnergy Corporation	Matthew Augustin		Affirmative	N/A
5	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Third-Party Comments
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	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	Comments Submitted
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	Third-Party Comments
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Abstain	N/A
5	Nebraska Public Power District	Ronald Bender		Affirmative	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Third-Party Comments

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	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	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Michael Johnson	Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		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	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	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		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Cleco Corporation	Robert Hirchak	Clay Walker	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler	Qinling Zheng	Affirmative	N/A
6	Constellation	Kimberly Turco	Marie Potter	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	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	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Negative	Comments Submitted
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Third-Party Comments
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		Affirmative	N/A
6	PSEG - PSEG Energy Resources and Trade LLC	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	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		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	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Abstain	N/A
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
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

BALLOT RESULTS

Comment: View Comment Results (/CommentResults/Index/348)
Ballot Name: 2021-03 CIP-002 Non-binding Poll AB 3 NB
Voting Start Date: 10/4/2024 12:01:00 AM
Voting End Date: 10/15/2024 8:00:00 PM
Ballot Type: NB
Ballot Activity: AB
Ballot Series: 3
Total # Votes: 238
Total Ballot Pool: 278
Quorum: 85.61
Quorum Established Date: 10/15/2024 3:04:42 PM
Weighted Segment Value: 80.11

Segment	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 1	78	1	39	0.75	13	0.25	17	9
Segment: 2	7	0.1	1	0.1	0	0	5	1
Segment: 3	65	1	37	0.787	10	0.213	12	6
Segment: 4	14	1	10	1	0	0	2	2
Segment: 5	69	1	34	0.791	9	0.209	11	15
Segment: 6	41	1	23	0.852	4	0.148	7	7
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	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes	Negative Fraction	Abstain	No Vote
Segment: 10	4	0.1	1	0.1	0	0	3	0
Totals:	278	5.2	145	4.38	36	0.82	57	40

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	Comments Submitted
1	Ameren - Ameren Services	Tamara Evey		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	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	Comments Submitted
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Negative	Comments Submitted
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	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	Theresa Ciancio		Affirmative	N/A
1	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	Comments Submitted
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	Comments Submitted
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Abstain	N/A
1	Long Island Power Authority	Isidoro Behar		None	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Abstain	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	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	Comments Submitted
1	National Grid USA	Michael Jones		Negative	Comments Submitted
1	NB Power Corporation	Jeffrey Streifling		Negative	Comments Submitted
1	Nebraska Public Power District	Jamison Cawley		Abstain	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Abstain	N/A
1	NiSource - Northern Indiana Public Service Co.	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		Affirmative	N/A
1	Omaha Public Power District	Doug Peterchuck		Affirmative	N/A
1	Oncor Electric Delivery	Byron Booker		Abstain	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		None	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		Negative	Comments Submitted
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		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 Pend Oreille County	Angela Hall		None	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	Sarah Blankenship	Israel Perez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Santee Cooper	Chris Wagner		Abstain	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	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	U.S. Bureau of Reclamation	Richard Jackson		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	California ISO	Darcy O'Connell		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Abstain	N/A
2	ISO New England, Inc.	John Pearson	John Galloway	Abstain	N/A
2	Midcontinent ISO, Inc.	Bobbi Welch		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	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		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Abstain	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	Comments Submitted
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		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		Negative	Comments Submitted
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	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	Great River Energy	Michael Brytowski		Negative	Comments Submitted
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	Comments Submitted
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		Affirmative	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		Negative	Comments Submitted
3	Nebraska Public Power District	Tony Eddleman		Abstain	N/A
3	New York Power Authority	Richard Machado		Negative	Comments Submitted

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	Comments Submitted
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	Comments Submitted
3	Northern California Power Agency	Michael Whitney	Mason Jones	Affirmative	N/A
3	NW Electric Power Cooperative, Inc.	Heath Henry		Negative	Comments Submitted
3	Ocala Utility Services	Neville Bowen	LaKenya Vannorman	None	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	OTP - Otter Tail Power Company	Wendi Olson		None	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	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		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	Affirmative	N/A
3	Salt River Project	Mathew Weber	Israel Perez	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Abstain	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Abstain	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	None	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		Abstain	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		None	N/A
5	Acciona Energy North America	Truong Le		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Abstain	N/A
5	APS - Arizona Public Service Co.	Andrew Smith	Brandon Smith	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	Comments Submitted
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Quincy Wang		Abstain	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Negative	Comments Submitted
5	Buckeye Power, Inc.	Kevin Zemanek	Ryan Strom	None	N/A
5	CMS Energy - Consumers Energy Company	David Greyerbiehl		None	N/A
5	Colorado Springs Utilities	Jeffrey Icke		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Con Ed - Consolidated Edison Co. of New York	Michelle Pagano		Affirmative	N/A
5	Constellation	Alison MacKellar	Marie Potter	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	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	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	Comments Submitted
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	Lincoln Electric System	Brittany Millard		Abstain	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
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		Negative	Comments Submitted
5	NB Power Corporation - New Brunswick Power Transmission Corporation	Erin Wilson		Negative	Comments Submitted
5	Nebraska Public Power District	Ronald Bender		Abstain	N/A
5	New York Power Authority	Zahid Qayyum		Negative	Comments Submitted
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	Comments Submitted
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	Affirmative	N/A
5	NRG - NRG Energy, Inc.	Patricia Lynch		Affirmative	N/A
5	OGE Energy - Oklahoma Gas and Electric Co.	Patrick Wells		None	N/A
5	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	Comments Submitted
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Michael Johnson	Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	Comments Submitted
5	Pine Gate Renewables	Michiko Sell		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		None	N/A
5	PSEG Nuclear LLC	Tim Kucey		None	N/A
5	Public Utility District No. 1 of Snohomish County	Becky Burden		Affirmative	N/A
5	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Abstain	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		None	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Abstain	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Abstain	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	Comments Submitted
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Negative	Comments Submitted
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler	Qinling Zheng	Affirmative	N/A
6	Constellation	Kimberly Turco	Marie Potter	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	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	Lakeland Electric	Paul Shipps		None	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	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	Comments Submitted
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	Comments Submitted
6	Northern California Power Agency	Dennis Sismaet		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		Affirmative	N/A
6	Portland General Electric Co.	Stefanie Burke		Abstain	N/A
6	Powerex Corporation	Raj Hundal		Abstain	N/A
6	PPL - Louisville Gas and Electric Co.	Linn Oelker		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	Affirmative	N/A
6	Salt River Project	Timothy Singh	Israel Perez	Affirmative	N/A
6	Santee Cooper	Marty Watson		Abstain	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Armando Rodriguez		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Abstain	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
10	SERC Reliability Corporation	Dave Krueger		Abstain	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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Standard Development Timeline

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

Description of Current Draft

This is the final draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023
45-day formal comment period with additional ballot	April 2 – May 16, 2024
45-day formal comment period with additional ballot	August 29 – October 15, 2024

Anticipated Actions	Date
Final ballot	November 13 – 22, 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):

Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-8

3. **Purpose:** To identify and categorize BES Cyber Systems (BCS) and their associated BES Cyber Assets (BCA) for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BCS could have on the reliable operation of the Bulk Electric System (BES). Identification and categorization of BCS support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. **Balancing Authority**

4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-8:

4.2.3.1. Cyber Systems at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Systems associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3. Cyber Systems, associated with communication networks and data communication links, between the Cyber Systems providing confidentiality and integrity of an ESP that extends to one or more geographic locations.

4.2.3.4. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.5. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See Implementation Plan for CIP-002

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts 1.1 through 1.3: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** RAS that support the reliable operation of the BES; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BCS according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BCS according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BCS according to Attachment 1, Section 3, if any (a discrete list of low impact BCS is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1.

R2. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Enforcement Program:
"Compliance Monitoring and 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 (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer identified BCS have not been categorized	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent, but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent, but less than or equal to 10 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category;	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent, but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high or medium impact BCS, more than 10 percent, but less than or equal to 15 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category;	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact

R #	Violation Severity Levels (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer high or medium BCS have not been identified.	OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than five, but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent, but less than or equal to 10 percent high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than five, but less than or equal to 10 high or medium BCS have not been identified.	OR For Responsible Entities with a total of 100 or fewer high or medium impact BCS, more than 10, but less than or equal to 15 identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 10 percent, but less than or equal to 15 percent high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than 10, but less than or equal to 15 high or medium BCS have not been identified.	BCS, more than 15 identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of high or medium impact BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BCS have not been identified.
R2	The Responsible Entity did not complete its review and update for the identification required for Requirement R1	The Responsible Entity did not complete its review and update for the identification required for Requirement R1	The Responsible Entity did not complete its review and update for the identification required for Requirement R1	The Responsible Entity did not complete its review and update for the identification required for Requirement R1

R #	Violation Severity Levels (CIP-002-8)			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	within 15 calendar months, but less than or equal to 16 calendar months of the previous review. (Part 2.1) OR The Responsible Entity did not complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months, but less than or equal to 16 calendar months of the previous approval. (Part 2.2)	within 16 calendar months, but less than or equal to 17 calendar months of the previous review. (Part2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months, but less than or equal to 17 calendar months of the previous approval. (Part 2.2)	within 17 calendar months, but less than or equal to 18 calendar months of the previous review. (Part 2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months, but less than or equal to 18 calendar months of the previous approval. (Part 2.2)	within 18 calendar months of the previous review. (Part 2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (Part 2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Implementation Plan for Project 2021-03
- CIP-002-8 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	5/14/2020	Adopted by the NERC Board of Trustees.	Modified Criterion 2.12.
7	TBD	Virtualization Modifications	

Version	Date	Action	Change Tracking
7	5/9/2024	Adopted by the NERC Board of Trustees.	
8	TBD	Transmission Owners Control Centers Update	

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. **High impact rating**

   Each BCS used by and located at any of the following:

   1.1. For Reliability Coordinators, each Control Center or backup Control Center used to perform the reliability tasks of the Reliability Coordinator.

   1.2. For Balancing Authorities, each Control Center or backup Control Center used to perform the reliability tasks of the Balancing Authority for: 1) generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

   1.3. For Transmission Operators and Transmission Owners, each Control Center or backup Control Center for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

   1.4 For Generator Operators, each Control Center or backup Control Center used to perform the reliability tasks of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. **Medium impact rating**

   Each BCS, not included in Section 1 above, associated with any of the following:

   2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

   2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

   2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

   2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

   2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher

voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each RAS or automated switching System that operates BES Elements, that, if destroyed, degraded, misused, or otherwise rendered unavailable, would cause one or more IROLs violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing UVLS or UFLS under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. For Generator Operators, each Control Center or backup Control Center used to perform the reliability tasks of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. For Transmission Operators and Transmission Owners, each Control Center or backup Control Center with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value

per BES Transmission Line," shown in the table below, for lines that are monitored and controlled by the Control Center or backup Control Center. Include each BES Transmission Line that is connected between two or more Transmission stations or substations.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:
Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may exclude the BES Transmission Lines that are contained in a single group of contiguous Elements from their "aggregate weighted value" calculation, where a group of contiguous Elements is defined as:

- a group of contiguous Elements emanating from multiple points of connection at 69 kV or higher;
- that are operated at less than 300 kV; and
- where the gross export does not exceed 75 MWh during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

2.13. For Balancing Authorities, each Control Center or backup Control Center used to perform the reliability tasks of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low impact rating

BCS not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS that support the reliable operation of the BES.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Standard Development Timeline

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

Description of Current Draft

This is the final draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023
45-day formal comment period with additional ballot	April 2 – May 16, 2024
45-day formal comment period with additional ballot	August 29 – October 15, 2024

Anticipated Actions	Date
Final Ballot	November 13 – 22, 2024
Board adoption	December 2024

CIP-002-8 is the combination of Project 2021-03's changes in on top of Project 2016-02's changes for virtualization. The following key describes the origin of changes in CIP-002-8:

Redline Text	Project 2021-03 Draft 3 changes
Redline Text	Project 2016-02 changes (Version 7)

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):

Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

<u>OR</u>

<u>One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.</u>

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization

2. **Number:** CIP-002-8~~5.1a~~

3. **Purpose:** To identify and categorize BES Cyber Systems (BCS) and their associated BES Cyber Assets (BCA) for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BCS~~BES Cyber Systems~~ could have on the reliable operation of the Bulk Electric System (BES).~~BES.~~ Identification and categorization of BCS~~BES Cyber Systems~~ support appropriate protection against compromises that could lead to misoperation or instability in the BES.

4. **Applicability:**

4.1. **Functional Entities:** For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. **Balancing Authority**

4.1.2. **Distribution Provider that owns** one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each ~~Special Protection System or~~ Remedial Action Scheme (RAS) where the RAS~~Special Protection System or Remedial Action Scheme~~ is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and

including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

~~**4.1.5. Interchange Coordinator or Interchange Authority**~~

~~4.1.6.~~4.1.5. **Reliability Coordinator**

~~4.1.7.~~4.1.6. **Transmission Operator**

~~4.1.8.~~4.1.7. **Transmission Owner**

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS~~Each Special Protection System or Remedial Action Scheme where the Special Protection System or Remedial Action Scheme~~ is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers:

All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-8~~5.1a~~:

4.2.3.1. Cyber Systems~~Assets~~ at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Systems~~Assets~~ associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESP).

4.2.3.3. Cyber Systems, associated with communication networks and data communication links, between the Cyber Systems providing confidentiality and integrity of an ESP that extends to one or more geographic locations.

~~**4.2.3.3.**~~**4.2.3.4.** The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

~~**4.2.3.4.**~~**4.2.3.5.** For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

~~**5.**~~ **Effective Dates:** See Implementation Plan for CIP-002

~~1. **24 Months Minimum –** CIP-002-5.1a shall become effective on the later of July 1, 2015, or the first calendar day of the ninth calendar quarter after the effective date of the order providing applicable regulatory approval.~~

~~2. In those jurisdictions where no regulatory approval is required CIP-002-5.1a shall become effective on the first day of the ninth calendar quarter following Board of Trustees' approval, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.~~

~~**6. Background:**~~

~~This standard provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems based on the impact of their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System. Several concepts provide the basis for the approach to the standard.~~

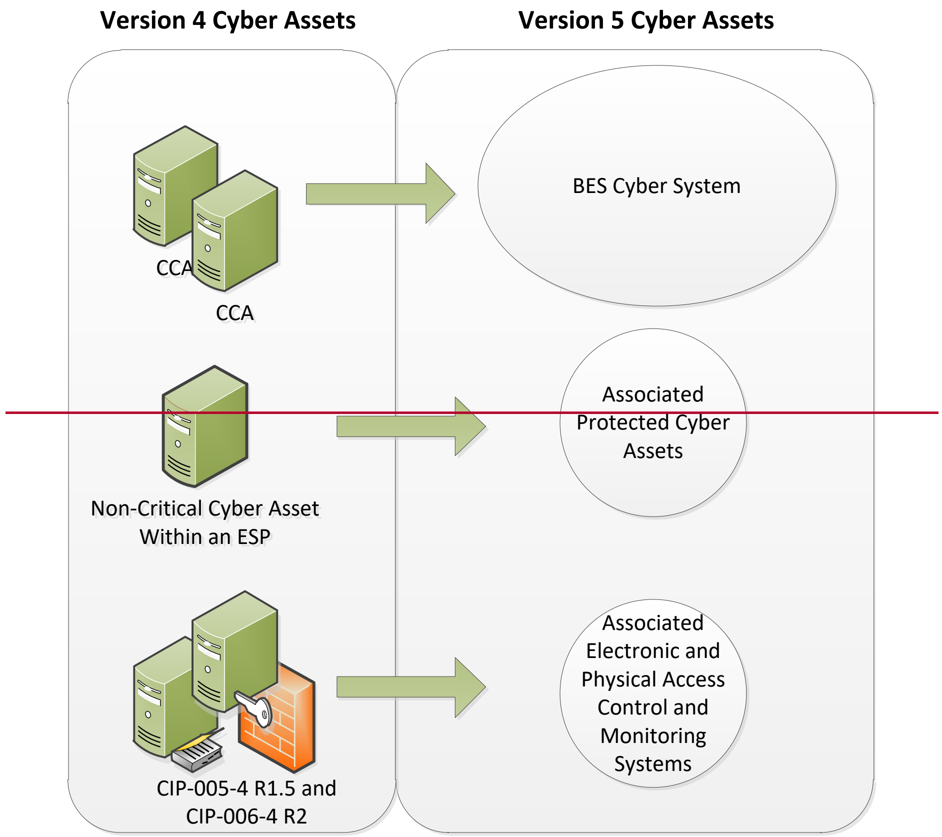
~~Throughout the standards, unless otherwise stated, bulleted items in the requirements are items that are linked with an "or," and numbered items are items that are linked with an "and."~~

5. ~~Many references in the Applicability section and the criteria in Attachment 1 of CIP-002 use a threshold of 300 MW for UFLS and UVLS. This particular threshold of 300 MW for UVLS and UFLS was provided in Version 1 of the CIP Cyber Security Standards. The threshold remains at 300 MW since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System. A review of UFLS~~

~~tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~**BES Cyber Systems**~~

~~One of the fundamental differences between Versions 4 and 5 of the CIP Cyber Security Standards is the shift from identifying Critical Cyber Assets to identifying BES Cyber Systems. This change results from the drafting team's review of the NIST Risk Management Framework and the use of an analogous term "information system" as the target for categorizing and applying security controls.~~



~~In transitioning from Version 4 to Version 5, a BES Cyber System can be viewed simply as a grouping of Critical Cyber Assets (as that term is used in Version 4). The CIP Cyber Security Standards use the "BES Cyber System" term primarily to provide a higher level for referencing the object of a requirement. For example, it becomes possible to apply requirements dealing with recovery and malware protection to a grouping rather than individual Cyber Assets, and it becomes clearer in the requirement that malware protection applies to the system as a whole and may not be necessary for every individual device to comply.~~

~~Another reason for using the term "BES Cyber System" is to provide a convenient level at which a Responsible Entity can organize their documented implementation of the requirements and compliance evidence. Responsible Entities can use the well-developed concept of a *security plan* for each BES Cyber System to document the programs, processes, and plans in place to comply with security requirements.~~

~~It is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System. For example, the Responsible Entity might choose to view an entire plant control system as a single BES Cyber System, or it might choose to view certain components of the plant control system as distinct BES Cyber Systems. The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~

~~Reliable Operation of the BES~~

~~The scope of the CIP Cyber Security Standards is restricted to BES Cyber Systems that would impact the reliable operation of the BES. In order to identify BES Cyber Systems, Responsible Entities determine whether the BES Cyber Systems perform or support any BES reliability function according to those reliability tasks identified for their reliability function and the corresponding functional entity's responsibilities as defined in its relationships with other functional entities in the NERC Functional Model. This ensures that the *initial* scope for consideration includes only those BES Cyber Systems and their associated BES Cyber Assets that perform or support the reliable operation of the BES. The definition of BES Cyber Asset provides the basis for this scoping.~~

~~Real-time Operations~~

~~One characteristic of the BES Cyber Asset is a real-time scoping characteristic. The time horizon that is significant for BES Cyber Systems and BES Cyber Assets subject to the application of these Version 5 CIP Cyber Security Standards is defined as that which is material to real-time operations for the reliable operation of the BES. To provide a better defined time horizon than "Real-time," BES Cyber Assets are those Cyber Assets that, if rendered unavailable, degraded, or misused, would adversely impact the reliable operation of the BES within 15 minutes of the activation or exercise of the compromise. This time window must not include in its consideration the activation of redundant BES Cyber Assets or BES Cyber Systems: from the cyber security standpoint, redundancy does not mitigate cyber security vulnerabilities.~~

~~Categorization Criteria~~

~~The criteria defined in Attachment 1 are used to categorize BES Cyber Systems into impact categories. Requirement 1 only requires the discrete identification of BES Cyber Systems for those in the high impact and medium impact categories. All BES Cyber Systems for Facilities not included in Attachment 1 – Impact Rating Criteria, Criteria 1.1 to 1.4 and Criteria 2.1 to 2.11 default to be low impact.~~

~~This general process of categorization of BES Cyber Systems based on impact on the reliable operation of the BES is consistent with risk management approaches for the~~

~~purpose of application of cyber security requirements in the remainder of the Version 5 CIP Cyber Security Standards.~~

~~**Electronic Access Control or Monitoring Systems, Physical Access Control Systems, and Protected Cyber Assets that are associated with BES Cyber Systems**~~

~~BES Cyber Systems have associated Cyber Assets, which, if compromised, pose a threat to the BES Cyber System by virtue of: (a) their location within the Electronic Security Perimeter (Protected Cyber Assets), or (b) the security control function they perform (Electronic Access Control or Monitoring Systems and Physical Access Control Systems). These Cyber Assets include:~~

~~**Electronic Access Control or Monitoring Systems ("EACMS")** – Examples include: Electronic Access Points, Intermediate Systems, authentication servers (e.g., RADIUS servers, Active Directory servers, Certificate Authorities), security event monitoring systems, and intrusion detection systems.~~

~~**Physical Access Control Systems ("PACS")**– Examples include: authentication servers, card systems, and badge control systems.~~

~~**Protected Cyber Assets ("PCA")** – Examples may include, to the extent they are within the ESP: file servers, ftp servers, time servers, LAN switches, networked printers, digital fault recorders, and emission monitoring systems.~~

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts~~parts~~ 1.1 through 1.3: *[Violation Risk Factor: High][Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** RAS~~Special Protection Systems~~ that support the reliable operation of the BES~~Bulk Electric System~~; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BCS~~BES Cyber Systems~~ according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BCS~~BES Cyber Systems~~ according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BCS~~BES Cyber System~~ according to Attachment 1, Section 3, if any (a discrete list of low impact BCS~~BES Cyber Systems~~ is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1~~, and Parts 1.1 and 1.2~~.

R2. Each~~The~~ Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

C. Compliance

1. **Compliance Monitoring Process:**

   1.1. **Compliance Enforcement Authority:**
   "~~The Regional Entity shall serve as the~~ Compliance Enforcement Authority" means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards. ~~("CEA") unless the applicable entity is owned, operated, or controlled by the Regional Entity. In such cases the ERO or a Regional Entity approved by FERC or other applicable governmental authority shall serve as the CEA.~~

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

   - Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
   - If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
   - The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

   1.3. **Compliance Monitoring and Enforcement Program~~Assessment Processes~~:**
   "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. ~~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

- ~~Compliance Audit~~
- ~~Self-Certification~~
- ~~Spot Checking~~
- ~~Compliance Investigation~~
- ~~Self-Reporting~~
- ~~Complaint~~

~~1.4. Additional Compliance Information~~

- ~~None~~

~~2. Table of Compliance Elements~~

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-~~85.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	~~Operations Planning~~	~~High~~	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, five	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-8~~5.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			percent or fewer of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, five or fewer identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, five	For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than five percent but less than or equal to 10 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~and BES Cyber Systems~~, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly	For Responsible Entities with more than a total of 100 high or medium impact BCS~~BES Cyber Systems~~, more than 10 percent but less than or equal to 15 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high or medium impact BCS~~and BES Cyber Assets~~, more than 10 but less than or equal to 15 identified BCS~~BES Cyber Assets~~ have not been categorized or have been incorrectly	BCS~~BES Cyber Systems~~, more than 15 percent of identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than 15 identified BCS~~BES Cyber Systems~~ have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-~~85.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			percent or fewer high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, five or fewer high or medium BCS~~BES Cyber Systems~~ have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than five percent but less than or equal to 10 percent high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than five but less than or equal to 10 high or medium BCS~~BES Cyber Systems~~ have not been identified.	categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS~~BES Cyber Systems~~, more than 10 percent but less than or equal to 15 percent high or medium BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS~~BES Cyber Systems~~, more than 10 but less than or equal to 15 high or medium BCS~~BES Cyber Systems~~ have not been identified.	and medium impact BCS~~BES Cyber Systems~~, more than 15 percent of high or medium impact BCS~~BES Cyber Systems~~ have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BCS~~BES Cyber Systems~~ have not been identified.

R #	~~Time Horizon~~	~~VRF~~	Violation Severity Levels (CIP-002-8~~5.1a~~)			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	~~Operations Planning~~	~~Lower~~	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 15 calendar months but less than or equal to 16 calendar months of the previous review. (Part 2~~R2~~.1) OR The Responsible Entity did not complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (Part 2~~R2~~.2)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 16 calendar months but less than or equal to 17 calendar months of the previous review. (Part2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (Part 2~~R2~~.2)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 17 calendar months but less than or equal to 18 calendar months of the previous review. (Part 2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (Part 2~~R2~~.2)	The Responsible Entity did not complete its review and update for the identification required for Requirement R1 within 18 calendar months of the previous review. (Part 2~~R2~~.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (Part 2~~R2~~.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Implementation Plan for Project 2021-03

~~None.~~

- CIP-002-8 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	5/14/2020	Adopted by the NERC Board of Trustees.	Modified Criterion 2.12.
7	TBD	Virtualization Modifications	

Version	Date	Action	Change Tracking
7	5/9/2024	Adopted by the NERC Board of Trustees.	
8	TBD	-Transmission Owners Control Centers Update	

~~5.1a –~~Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. High impact rating~~Impact Rating (H)~~

Each BCS~~BES Cyber System~~ used by and located at any of the following:

1.1. For Reliability Coordinators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Reliability Coordinator.

1.2. For Balancing Authorities, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Balancing Authority: 1) for generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) for one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

1.3. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center ~~used to perform the functional obligations of the Transmission Operator~~ for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

1.4 For Generator Operators, e~~E~~ach Control Center or backup Control Center used to perform the reliability tasks~~functional obligations~~ of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. Medium impact rating~~Impact Rating (M)~~

Each BCS~~BES Cyber System~~, not included in Section 1 above, associated with any of the following:

2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BCS~~BES Cyber Systems~~ that meet this criterion are each discrete~~those~~ shared BCS~~BES Cyber Systems~~ that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BCS~~BES Cyber Systems~~ that meet this criterion are each discrete~~those~~ shared BCS~~BES Cyber~~

~~Systems~~ that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each ~~Special Protection System (SPS), Remedial Action Scheme (~~RAS~~),~~ or automated switching System that operates BES Elements, that, if destroyed, degraded, misused, or otherwise rendered unavailable, would cause one or more Interconnection Reliability Operating Limits (IROLs) violations for failure to operate as designed or

cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing undervoltage load shedding (UVLS) or underfrequency load shedding (UFLS) under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. For Generator Operators, e~~E~~ach Control Center or backup Control Center~~, not already included in High Impact Rating (H)~~, ~~above,~~ used to perform the reliability tasks~~functional obligations~~ of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. For Transmission Operators and Transmission Owners, e~~E~~ach Control Center or backup Control Center with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per BES Transmission Line," shown in the table below, for lines that are monitored and controlled by the Control Center or backup Control Center. Include each BES Transmission Line that is connected between two or more Transmission stations or substations. ~~used to perform the functional obligations of the Transmission Operator not included in High Impact Rating (H), above.~~

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:

Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may exclude the BES Transmission Lines that are contained in a single group of contiguous Elements from their "aggregate weighted value" calculation, where a group of contiguous Elements is defined as:

- a group of contiguous Elements emanating from multiple points of connection at 69 kV or higher;
- that are operated at less than 300 kV; and

- where the gross export does not exceed 75 MWh during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

~~2.12.~~2.13. For Balancing Authorities, e~~E~~ach Control Center or backup Control Center~~, not already included in High Impact Rating (H) above,~~ used to perform the reliability tasks~~functional obligations~~ of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low impact rating~~Impact Rating (L)~~

BCS ~~BES Cyber Systems~~ not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS~~Special Protection Systems~~ that support the reliable operation of the Bulk Electric System.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

~~Guidelines and Technical Basis~~ (Project 2021-03 decided to highlight the title versus the entire section of the GTB. The GTB sections were removed by Project 2016-02.)

~~Section 4 – Scope of Applicability of the CIP Cyber Security Standards~~

~~Section "4. Applicability" of the standards provides important information for Responsible Entities to determine the scope of the applicability of the CIP Cyber Security Requirements.~~

~~Section "4.1. Functional Entities" is a list of NERC functional entities to which the standard applies. If the entity is registered as one or more of the functional entities listed in section 4.1, then the NERC CIP Cyber Security Standards apply. Note that there is a qualification in section 4.1 that restricts the applicability in the case of Distribution Providers to only those that own certain types of systems and equipment listed in 4.2.~~

~~Section "4.2. Facilities" defines the scope of the Facilities, systems, and equipment owned by the Responsible Entity, as qualified in section 4.1, that is subject to the requirements of the standard. In addition to the set of BES Facilities, Control Centers, and other systems and equipment, the list includes the qualified set of systems and equipment owned by Distribution Providers. While the NERC Glossary term "Facilities" already includes the BES characteristic, the additional use of the term BES here is meant to reinforce the scope of applicability of these Facilities where it is used, especially in this applicability scoping section. This in effect sets the scope of Facilities, systems, and equipment that is subject to the standards. This section is especially significant in CIP-002-5.1a and represents the total scope of Facilities, systems, and equipment to which the criteria in Attachment 1 apply. This is important because it determines the balance of these Facilities, systems, and equipment that are Low Impact once those that qualify under the High and Medium Impact categories are filtered out.~~

~~For the purpose of identifying groups of Facilities, systems, and equipment, whether by location or otherwise, the Responsible Entity identifies assets as described in Requirement R1 of CIP-002-5.1a. This is a process familiar to Responsible Entities that have to comply with versions 1, 2, 3, and 4 of the CIP standards for Critical Assets. As in versions 1, 2, 3, and 4, Responsible Entities may use substations, generation plants, and Control Centers at single site locations as identifiers of these groups of Facilities, systems, and equipment.~~

~~CIP-002-5.1a~~

~~CIP-002-5.1a requires that applicable Responsible Entities categorize their BES Cyber Systems and associated BES Cyber Assets according to the criteria in Attachment 1. A BES Cyber Asset includes in its definition, "…that if rendered unavailable, degraded, or misused would, within 15 minutes adversely impact the reliable operation of the BES."~~

~~The following provides guidance that a Responsible Entity may use to identify the BES Cyber Systems that would be in scope. The concept of BES reliability operating service is useful in providing Responsible Entities with the option of a defined process for scoping those BES Cyber~~

~~Systems that would be subject to CIP-002-5.1a. The concept includes a number of named BES reliability operating services. These named services include:~~

~~Dynamic Response to BES conditions~~
~~Balancing Load and Generation~~
~~Controlling Frequency (Real Power)~~
~~Controlling Voltage (Reactive Power)~~
~~Managing Constraints~~
~~Monitoring & Control~~
~~Restoration of BES~~
~~Situational Awareness~~
~~Inter-Entity Real-Time Coordination and Communication~~

~~Responsibility for the reliable operation of the BES is spread across all Entity Registrations. Each entity registration has its own special contribution to reliable operations and the following discussion helps identify which entity registration, in the context of those functional entities to which these CIP standards apply, performs which reliability operating service, as a process to identify BES Cyber Systems that would be in scope. The following provides guidance for Responsible Entities to determine applicable reliability operations services according to their Function Registration type.~~

~~Entity Registration~~	~~RC~~	~~BA~~	~~TOP~~	~~TO~~	~~DP~~	~~GOP~~	~~GO~~
~~Dynamic Response~~		~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Balancing Load & Generation~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~	~~X~~
~~Controlling Frequency~~		~~X~~				~~X~~	~~X~~
~~Controlling Voltage~~			~~X~~	~~X~~	~~X~~		~~X~~
~~Managing Constraints~~	~~X~~		~~X~~			~~X~~	
~~Monitoring and Control~~			~~X~~			~~X~~	
~~Restoration~~			~~X~~			~~X~~	
~~Situation Awareness~~	~~X~~	~~X~~	~~X~~			~~X~~	
~~Inter-Entity coordination~~	~~X~~	~~X~~	~~X~~	~~X~~		~~X~~	~~X~~

~~Dynamic Response~~

~~The Dynamic Response Operating Service includes those actions performed by BES Elements or subsystems which are automatically triggered to initiate a response to a BES condition. These actions are triggered by a single element or control device or a combination of these elements or devices in concert to perform an action or cause a condition in reaction to the triggering action or condition. The types of dynamic responses that may be considered as potentially having an impact on the BES are:~~

- ~~Spinning reserves (contingency reserves)~~
  - ~~Providing actual reserve generation when called upon (GO,GOP)~~

- ~~Monitoring that reserves are sufficient (BA)~~
- ~~Governor Response~~
  - ~~Control system used to actuate governor response (GO)~~
- ~~Protection Systems (transmission & generation)~~
  - ~~Lines, buses, transformers, generators (DP, TO, TOP, GO, GOP)~~
  - ~~Zone protection for breaker failure (DP, TO, TOP)~~
  - ~~Breaker protection (DP, TO, TOP)~~
  - ~~Current, frequency, speed, phase (TO,TOP, GO,GOP)~~
- ~~Special Protection Systems or Remedial Action Schemes~~
  - ~~Sensors, relays, and breakers, possibly software (DP, TO, TOP)~~
- ~~Under and Over Frequency relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Under and Over Voltage relay protection (includes automatic load shedding)~~
  - ~~Sensors, relays & breakers (DP)~~
- ~~Power System Stabilizers (GO)~~

~~Balancing Load and Generation~~

~~The Balancing Load and Generation Operations Service includes activities, actions and conditions necessary for monitoring and controlling generation and load in the operations planning horizon and in real-time. Aspects of the Balancing Load and Generation function include, but are not limited to:~~

- ~~Calculation of Area Control Error (ACE)~~
  - ~~Field data sources (real time tie flows, frequency sources, time error, etc) (TO, TOP)~~
  - ~~Software used to perform calculation (BA)~~
- ~~Demand Response~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP,DP)~~
- ~~Manually Initiated Load shedding~~
  - ~~Ability to identify load change need (BA)~~
  - ~~Ability to implement load changes (TOP, DP)~~
- ~~Non-spinning reserve (contingency reserve)~~
  - ~~Know generation status, capability, ramp rate, start time (GO, BA)~~
  - ~~Start units and provide energy (GOP)~~

~~**Controlling Frequency (Real Power)**~~

~~The Controlling Frequency Operations Service includes activities, actions and conditions which ensure, in real time, that frequency remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Frequency function include, but are limited to:~~

- ~~Generation Control (such as AGC)~~
  - ~~ACE, current generator output, ramp rate, unit characteristics (BA, GOP, GO)~~
  - ~~Software to calculate unit adjustments (BA)~~
  - ~~Transmit adjustments to individual units (GOP)~~
  - ~~Unit controls implementing adjustments (GOP)~~
- ~~Regulation (regulating reserves)~~
  - ~~Frequency source, schedule (BA)~~
  - ~~Governor control system (GO)~~

~~**Controlling Voltage (Reactive Power)**~~

~~The Controlling Voltage Operations Service includes activities, actions and conditions which ensure, in real time, that voltage remains within bounds acceptable for the reliability or operability of the BES. Aspects of the Controlling Voltage function include, but are not limited to:~~

- ~~Automatic Voltage Regulation (AVR)~~
  - ~~Sensors, stator control system, feedback (GO)~~
- ~~Capacitive resources~~
  - ~~Status, control (manual or auto), feedback (TOP, TO,DP)~~
- ~~Inductive resources (transformer tap changer, or inductors)~~
  - ~~Status, control (manual or auto), feedback (TOP,TO,DP)~~
- ~~Static VAR Compensators (SVC)~~
  - ~~Status, computations, control (manual or auto), feedback (TOP, TO,DP)~~

~~**Managing Constraints**~~

~~Managing Constraints includes activities, actions and conditions that are necessary to ensure that elements of the BES operate within design limits and constraints established for the reliability and operability of the BES. Aspects of the Managing Constraints include, but are not limited to:~~

- ~~Available Transfer Capability (ATC) (TOP)~~

- ~~Interchange schedules (TOP, RC)~~
- ~~Generation re-dispatch and unit commit (GOP)~~
- ~~Identify and monitor SOL's & IROL's (TOP, RC)~~
- ~~Identify and monitor Flow gates (TOP, RC)~~

~~Monitoring and Control~~

~~Monitoring and Control includes those activities, actions and conditions that provide monitoring and control of BES Elements. An example aspect of the Control and Operation function is:~~

- ~~All methods of operating breakers and switches~~
  - ~~SCADA (TOP, GOP)~~
  - ~~Substation automation (TOP)~~

~~Restoration of BES~~

~~The Restoration of BES Operations Service includes activities, actions and conditions necessary to go from a shutdown condition to an operating condition delivering electric power without external assistance. Aspects of the Restoration of BES function include, but are not limited to:~~

- ~~Restoration including planned cranking path~~
  - ~~Through black start units (TOP, GOP)~~
  - ~~Through tie lines (TOP, GOP)~~
- ~~Off-site power for nuclear facilities. (TOP, TO, BA, RC, DP, GO, GOP)~~
- ~~Coordination (TOP, TO, BA, RC, DP, GO, GOP)~~

~~Situational Awareness~~

~~The Situational Awareness function includes activities, actions and conditions established by policy, directive or standard operating procedure necessary to assess the current condition of the BES and anticipate effects of planned and unplanned changes to conditions. Aspects of the Situation Awareness function include:~~

- ~~Monitoring and alerting (such as EMS alarms) (TOP, GOP, RC,BA)~~
- ~~Change management (TOP,GOP,RC,BA)~~
- ~~Current Day and Next Day planning (TOP)~~
- ~~Contingency Analysis (RC)~~
- ~~Frequency monitoring (BA, RC)~~

~~Inter-Entity Coordination~~

~~The Inter-Entity coordination and communication function includes activities, actions, and conditions established by policy, directive, or standard operating procedure necessary for the coordination and communication between Responsible Entities to ensure the reliability and operability of the BES. Aspects of the Inter-Entity Coordination and Communication function include:~~

- ~~Scheduled interchange (BA,TOP,GOP,RC)~~
- ~~Facility operational data and status (TO, TOP, GO, GOP, RC, BA)~~
- ~~Operational directives (TOP, RC, BA)~~

~~Applicability to Distribution Providers~~

~~It is expected that only Distribution Providers that own or operate facilities that qualify in the Applicability section will be subject to these Version 5 Cyber Security Standards. Distribution Providers that do not own or operate any facility that qualifies are not subject to these standards. The qualifications are based on the requirements for registration as a Distribution Provider and on the requirements applicable to Distribution Providers in NERC Standard EOP-005.~~

~~Requirement R1:~~

~~Requirement R1 implements the methodology for the categorization of BES Cyber Systems according to their impact on the BES. Using the traditional risk assessment equation, it reduces the measure of the risk to an impact (consequence) assessment, assuming the vulnerability index of 1 (the Systems are assumed to be vulnerable) and a probability of threat of 1 (100 percent). The criteria in Attachment 1 provide a measure of the impact of the BES assets supported by these BES Cyber Systems.~~

~~Responsible Entities are required to identify and categorize those BES Cyber Systems that have high and medium impact. BES Cyber Systems for BES assets not specified in Attachment 1, Criteria 1.1 – 1.4 and Criteria 2.1 – 2.11 default to low impact.~~

~~Attachment 1~~

~~Overall Application~~

~~In the application of the criteria in Attachment 1, Responsible Entities should note that the approach used is based on the impact of the BES Cyber System as measured by the bright-line criteria defined in Attachment 1.~~

- ~~When the drafting team uses the term “Facilities”, there is some latitude to Responsible Entities to determine included Facilities. The term Facility is defined in the NERC Glossary of Terms as “A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).” In most cases, the criteria refer to a group of Facilities in a given location that supports the reliable operation of the BES. For example, for Transmission assets, the substation may be~~

~~designated as the group of Facilities. However, in a substation that includes equipment that supports BES operations along with equipment that only supports Distribution operations, the Responsible Entity may be better served to consider only the group of Facilities that supports BES operation. In that case, the Responsible Entity may designate the group of Facilities by location, with qualifications on the group of Facilities that supports reliable operation of the BES, as the Facilities that are subject to the criteria for categorization of BES Cyber Systems. Generation Facilities are separately discussed in the Generation section below. In CIP-002-5.1a, these groups of Facilities, systems, and equipment are sometimes designated as BES assets. For example, an identified BES asset may be a named substation, generating plant, or Control Center. Responsible Entities have flexibility in how they group Facilities, systems, and equipment at a location.~~

- ~~In certain cases, a BES Cyber System may be categorized by meeting multiple criteria. In such cases, the Responsible Entity may choose to document all criteria that result in the categorization. This will avoid inadvertent miscategorization when it no longer meets one of the criteria, but still meets another.~~
- ~~It is recommended that each BES Cyber System should be listed by only one Responsible Entity. Where there is joint ownership, it is advisable that the owning Responsible Entities should formally agree on the designated Responsible Entity responsible for compliance with the standards.~~

~~High Impact Rating (H)~~

~~This category includes those BES Cyber Systems, used by and at Control Centers (and the associated data centers included in the definition of Control Centers), that perform the functional obligations of the Reliability Coordinator (RC), Balancing Authority (BA), Transmission Operator (TOP), or Generator Operator (GOP), as defined under the Tasks heading of the applicable Function and the Relationship with Other Entities heading of the functional entity in the NERC Functional Model, and as scoped by the qualification in Attachment 1, Criteria 1.1, 1.2, 1.3 and 1.4. While those entities that have been registered as the above-named functional entities are specifically referenced, it must be noted that there may be agreements where some of the functional obligations of a Transmission Operator may be delegated to a Transmission Owner (TO). In these cases, BES Cyber Systems at these TO Control Centers that perform these functional obligations would be subject to categorization as high impact. The criteria notably specifically emphasize functional obligations, not necessarily the RC, BA, TOP, or GOP facilities. One must note that the definition of Control Center specifically refers to reliability tasks for RCs, Bas, TOPs, and GOPs. A TO BES Cyber System in a TO facility that does not perform or does not have an agreement with a TOP to perform any of these functional tasks does not meet the definition of a Control Center. However, if that BES Cyber System operates any of the facilities that meet criteria in the Medium Impact category, that BES Cyber System would be categorized as a Medium Impact BES Cyber System.~~

~~The 3000 MW threshold defined in criterion 1.2 for BA Control Centers provides a sufficient differentiation of the threshold defined for Medium Impact BA Control Centers. An analysis of BA footprints shows that the majority of Bas with significant impact are covered under this criterion.~~

~~Additional thresholds as specified in the criteria apply for this category.~~

~~Medium Impact Rating (M)~~

~~Generation~~

~~The criteria in Attachment 1's medium impact category that generally apply to Generation Owner and Operator (GO/GOP) Registered Entities are criteria 2.1, 2.3, 2.6, 2.9, and 2.11. Criterion 2.13 for BA Control Centers is also included here.~~

- ~~Criterion 2.1 designates as medium impact those BES Cyber Systems that impact generation with a net Real Power capability exceeding 1500 MW. The 1500 MW criterion is sourced partly from the Contingency Reserve requirements in NERC standard BAL-002, whose purpose is "to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance." In particular, it requires that "as a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency." The drafting team used 1500 MW as a number derived from the most significant Contingency Reserves operated in various Bas in all regions.~~

  ~~In the use of net Real Power capability, the drafting team sought to use a value that could be verified through existing requirements as proposed by NERC standard MOD-024 and current development efforts in that area.~~

  ~~By using 1500 MW as a bright-line, the intent of the drafting team was to ensure that BES Cyber Systems with common mode vulnerabilities that could result in the loss of 1500 MW or more of generation at a single plant for a unit or group of units are adequately protected.~~

  ~~The drafting team also used additional time and value parameters to ensure the bright-lines and the values used to measure against them were relatively stable over the review period. Hence, where multiple values of net Real Power capability could be used for the Facilities' qualification against these bright-lines, the highest value was used.~~

- ~~In Criterion 2.3, the drafting team sought to ensure that BES Cyber Systems for those generation Facilities that have been designated by the Planning Coordinator or Transmission Planner as necessary to avoid BES Adverse Reliability Impacts in the planning horizon of one year or more are categorized as medium impact. In specifying a planning horizon of one year or more, the intent is to ensure that those are units that are identified as a result of a "long term" reliability planning, i.e that the plans are spanning an operating period of at least 12 months: it does not mean that the operating day for the unit is necessarily beyond one year, but that the period that is being planned for is more than 1 year: it is specifically intended to avoid designating generation that is required to be run to remediate short term emergency reliability issues. These Facilities may be designated as "Reliability Must Run," and this designation is distinct from those generation Facilities designated as "must run" for market stabilization purposes. Because the use of the term "must run" creates some confusion in many areas, the drafting team chose to avoid using this term and instead drafted the requirement in more generic reliability language. In~~

~~particular, the focus on preventing an Adverse Reliability Impact dictates that these units are designated as must run for reliability purposes beyond the local area. Those units designated as must run for voltage support in the local area would not generally be given this designation. In cases where there is no designated Planning Coordinator, the Transmission Planner is included as the Registered Entity that performs this designation.~~

~~If it is determined through System studies that a unit must run in order to preserve the reliability of the BES, such as due to a Category C3 contingency as defined in TPL-003, then BES Cyber Systems for that unit are categorized as medium impact.~~

~~The TPL standards require that, where the studies and plans indicate additional actions, that these studies and plans be communicated by the Planning Coordinator or Transmission Planner in writing to the Regional Entity/RRO. Actions necessary for the implementation of these plans by affected parties (generation owners/operators and Reliability Coordinators or other necessary party) are usually formalized in the form of an agreement and/or contract.~~

- ~~Criterion 2.6 includes BES Cyber Systems for those Generation Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2, **Establish and Communicate System Operating Limits**, R5.1.1 and R5.1.3.~~

  ~~IROLs may be based on dynamic System phenomena such as instability or voltage collapse. Derivation of these IROLs and their associated contingencies often considers the effect of generation inertia and AVR response.~~

- ~~Criterion 2.9 categorizes BES Cyber Systems for Special Protection Systems and Remedial Action Schemes as medium impact. Special Protection Systems and Remedial Action Schemes may be implemented to prevent disturbances that would result in exceeding IROLs if they do not provide the function required at the time it is required or if it operates outside of the parameters it was designed for. Generation Owners and Generator Operators which own BES Cyber Systems for such Systems and schemes designate them as medium impact.~~

- ~~Criterion 2.11 categorizes as medium impact BES Cyber Systems used by and at Control Centers that perform the functional obligations of the Generator Operator for an aggregate generation of 1500 MW or higher in a single interconnection, and that have not already been included in Part 1.~~

- ~~Criterion 2.13 categorizes as medium impact those BA Control Centers that "control" 1500 MW of generation or more in a single interconnection and that have not already been included in Part 1. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~Transmission~~

~~*The SDT uses the phrases "Transmission Facilities at a single station or substation" and "Transmission stations or substations" to recognize the existence of both stations and substations. Many entities in industry consider a substation to be a location with physical borders (i.e. fence, wall, etc.) that contains at least an autotransformer. Locations also exist that do not contain autotransformers, and many entities in industry refer to those locations as stations (or switchyards). Therefore, the SDT chose to use both "station" and "substation" to refer to the locations where groups of Transmission Facilities exist.*~~

- ~~Criteria 2.2, 2.4 through 2.10, and 2.12 in Attachment 1 are the criteria that are applicable to Transmission Owners and Operators. In many of the criteria, the impact threshold is defined as the capability of the failure or compromise of a System to result in exceeding one or more Interconnection Reliability Operating Limits (IROLs). Criterion 2.2 includes BES Cyber Systems for those Facilities in Transmission Systems that provide reactive resources to enhance and preserve the reliability of the BES. The nameplate value is used here because there is no NERC requirement to verify actual capability of these Facilities. The value of 1000 MVARs used in this criterion is a value deemed reasonable for the purpose of determining criticality.~~

- ~~Criterion 2.4 includes BES Cyber Systems for any Transmission Facility at a substation operated at 500 kV or higher. While the drafting team felt that Facilities operated at 500 kV or higher did not require any further qualification for their role as components of the backbone on the Interconnected BES, Facilities in the lower EHV range should have additional qualifying criteria for inclusion in the medium impact category.~~

  ~~It must be noted that if the collector bus for a generation plant (i.e. the plant is smaller in aggregate than the threshold set for generation in Criterion 2.1) is operated at 500kV, the collector bus should be considered a Generation Interconnection Facility, and not a Transmission Facility, according to the "Final Report from the Ad Hoc Group for Generation Requirements at the Transmission Interface." This collector bus would not be a facility for a medium impact BES Cyber System because it does not significantly affect the 500kV Transmission grid; it only affects a plant which is below the generation threshold.~~

- ~~Criterion 2.5 includes BES Cyber Systems for facilities at the lower end of BES Transmission with qualifications for inclusion if they are deemed highly likely to have significant impact on the BES. While the criterion has been specified as part of the rationale for requiring protection for significant impact on the BES, the drafting team included, in this criterion, additional qualifications that would ensure the required level of impact to the BES. The drafting team:~~

  - ~~Excluded radial facilities that would only provide support for single generation facilities.~~

  - ~~Specified interconnection to at least three transmission stations or substations to ensure that the level of impact would be appropriate.~~

  ~~The total aggregated weighted value of 3,000 was derived from weighted values related to three connected 345 kV lines and five connected 230 kV lines at a transmission station or~~

~~substation. The total aggregated weighted value is used to account for the true impact to the BES, irrespective of line kV rating and mix of multiple kV rated lines.~~

~~Additionally, in NERC's document "Integrated Risk Assessment Approach – Refinement to Severity Risk Index", Attachment 1, the report used an average MVA line loading based on kV rating:~~

- ~~230 kV –> 700 MVA~~
- ~~345 kV –> 1,300 MVA~~
- ~~500 kV –> 2,000 MVA~~
- ~~765 kV –> 3,000 MVA~~

~~In the terms of applicable lines and connecting "other Transmission stations or substations" determinations, the following should be considered:~~

- ~~For autotransformers in a station, Responsible Entities have flexibility in determining whether the groups of Facilities are considered a single substation or station location or multiple substations or stations. In most cases, Responsible Entities would probably consider them as Facilities at a single substation or station unless geographically dispersed. In these cases of these transformers being within the "fence" of the substation or station, autotransformers may not count as separate connections to other stations. The use of common BES Cyber Systems may negate any rationale for any consideration otherwise. In the case of autotransformers that are geographically dispersed from a station location, the calculation would take into account the connections in and out of each station or substation location.~~

- ~~Multiple-point (or multiple-tap) lines are considered to contribute a single weight value per line and affect the number of connections to other stations. Therefore, a single 230 kV multiple-point line between three Transmission stations or substations would contribute an aggregated weighted value of 700 and connect Transmission Facilities at a single station or substation to two other Transmission stations or substations.~~

- ~~Multiple lines between two Transmission stations or substations are considered to contribute multiple weight values per line, but these multiple lines between the two stations only connect one station to one other station. Therefore, two 345 kV lines between two Transmission stations or substations would contribute an aggregated weighted value of 2600 and connect Transmission Facilities at a single station or substation to one other Transmission station or substation.~~

~~Criterion 2.5's qualification for Transmission Facilities at a Transmission station or substation is based on 2 distinct conditions.~~

1. ~~The first condition is that Transmission Facilities at a single station or substation where that station or substation connect, at voltage levels of 200 kV or higher to three (3) other stations or substations, to three other stations or substations.~~

~~This qualification is meant to ensure that connections that operate at voltages of 500 kV or higher are included in the count of connections to other stations or substations as well.~~

~~2. The second qualification is that the aggregate value of all lines entering or leaving the station or substation must exceed 3000. This qualification does not include the consideration of lines operating at lower than 200 kV, or 500 kV or higher, the latter already qualifying as medium impact under criterion 2.4. : there is no value to be assigned to lines at voltages of less than 200 kV or 500 kV or higher in the table of values for the contribution to the aggregate value of 3000.~~

~~The Transmission Facilities at the station or substation must meet both qualifications to be considered as qualified under criterion 2.5.~~

- ~~Criterion 2.6 include BES Cyber Systems for those Transmission Facilities that have been identified as critical to the derivation of IROLs and their associated contingencies, as specified by FAC-014-2,~~ ~~**Establish and Communicate System Operating Limits**~~~~, R5.1.1 and R5.1.3.~~
- ~~Criterion 2.7 is sourced from the NUC-001 NERC standard, Requirement R9.2.2, for the support of Nuclear Facilities. NUC-001 ensures that reliability of NPIR's are ensured through adequate coordination between the Nuclear Generator Owner/Operator and its Transmission provider "for the purpose of ensuring nuclear plant safe operation and shutdown." In particular, there are specific requirements to coordinate physical and cyber security protection of these interfaces.~~
- ~~Criterion 2.8 designates as medium impact those BES Cyber Systems that impact Transmission Facilities necessary to directly support generation that meet the criteria in Criteria 2.1 (generation Facilities with output greater than 1500 MW) and 2.3 (generation Facilities generally designated as "must run" for wide area reliability in the planning horizon). The Responsible Entity can request a formal statement from the Generation owner as to the qualification of generation Facilities connected to their Transmission systems.~~
- ~~Criterion 2.9 designates as medium impact those BES Cyber Systems for those Special Protection Systems (SPS), Remedial Action Schemes (RAS), or automated switching Systems installed to ensure BES operation within IROLs. The degradation, compromise or unavailability of these BES Cyber Systems would result in exceeding IROLs if they fail to operate as designed. By the definition of IROL, the loss or compromise of any of these have Wide Area impacts.~~
- ~~Criterion 2.10 designates as medium impact those BES Cyber Systems for Systems or Elements that perform automatic Load shedding, without human operator initiation, of 300 MW or more. The SDT spent considerable time discussing the wording of Criterion 2.10, and chose the term "Each" to represent that the criterion applied to a discrete System or Facility. In the drafting of this criterion, the drafting team sought to include only those Systems that did not require human operator initiation, and targeted in particular those underfrequency load shedding (UFLS) Facilities and systems and undervoltage load shedding (UVLS) systems~~

~~and Elements that would be subject to a regional Load shedding requirement to prevent Adverse Reliability Impact. These include automated UFLS systems or UVLS systems that are capable of Load shedding 300 MW or more. It should be noted that those qualifying systems which require a human operator to arm the system, but once armed, trigger automatically, are still to be considered as not requiring human operator initiation and should be designated as medium impact. The 300 MW threshold has been defined as the aggregate of the highest MW Load value, as defined by the applicable regional Load Shedding standards, for the preceding 12 months to account for seasonal fluctuations.~~

~~This particular threshold (300 MW) was provided in CIP, Version 1. The SDT believes that the threshold should be lower than the 1500MW generation requirement since it is specifically addressing UVLS and UFLS, which are last ditch efforts to save the Bulk Electric System and hence requires a lower threshold. A review of UFLS tolerances defined within regional reliability standards for UFLS program requirements to date indicates that the historical value of 300 MW represents an adequate and reasonable threshold value for allowable UFLS operational tolerances.~~

~~In ERCOT, the Load acting as a Resource ("LaaR") Demand Response Program is not part of the regional load shedding program, but an ancillary services market. In general, similar demand response programs that are not part of the NERC or regional reliability Load shedding programs, but are offered as components of an ancillary services market do not qualify under this criterion.~~

~~The language used in section 4 for UVLS and UFLS and in criterion 2.10 of Attachment 1 is designed to be consistent with requirements set in the PRC standards for UFLS and UVLS.~~

- ~~Criterion 2.12 categorizes as medium impact those BES Cyber Systems used by and at Control Centers and associated data centers performing the functional obligations of a Transmission Operator and that have not already been categorized as high impact.~~
- ~~Criterion 2.13 categorizes as Medium Impact those BA Control Centers that "control" 1500 MW of generation or more in a single Interconnection. The 1500 MW threshold is consistent with the impact level and rationale specified for Criterion 2.1.~~

~~Low Impact Rating (L)~~

~~BES Cyber Systems not categorized in high impact or medium impact default to low impact. Note that low impact BES Cyber Systems do not require discrete identification.~~

~~Restoration Facilities~~

- ~~Several discussions on the CIP Version 5 standards suggest entities owning Blackstart Resources and Cranking Paths might elect to remove those services to avoid higher compliance costs. For example, one Reliability Coordinator reported a 25% reduction of Blackstart Resources as a result of the Version 1 language, and there could be more entities that make this choice under Version 5.~~

  ~~In response, the CIP Version 5 drafting team sought informal input from NERC's Operating and Planning Committees. The committees indicate there has already been a reduction in~~

~~Blackstart Resources because of increased CIP compliance costs, environmental rules, and other risks; continued inclusion within Version 5 at a category that would very significantly increase compliance costs can result in further reduction of a vulnerable pool.~~

~~The drafting team moved from the categorization of restoration assets such as Blackstart Resources and Cranking Paths as medium impact (as was the case in earlier drafts) to categorization of these assets as low impact as a result of these considerations. This will not relieve asset owners of all responsibilities, as would have been the case in CIP-002, Versions 1-4 (since only Cyber Assets with routable connectivity which are essential to restoration assets are included in those versions). Under the low impact categorization, those assets will be protected in the areas of cyber security awareness, physical access control, and electronic access control, and they will have obligations regarding incident response. This represents a net gain to bulk power system reliability, however, since many of those assets do not meet criteria for inclusion under Versions 1-4.~~

~~Weighing the risks to overall BES reliability, the drafting team determined that this re-categorization represents the option that would be the least detrimental to restoration function and, thus, overall BES reliability. Removing Blackstart Resources and Cranking Paths from medium impact promotes overall reliability, as the likely alternative is fewer Blackstart Resources supporting timely restoration when needed.~~

~~BES Cyber Systems for generation resources that have been designated as Blackstart Resources in the Transmission Operator's restoration plan default to low impact. NERC Standard EOP-005-2 requires the Transmission Operator to have a Restoration Plan and to list its Blackstart Resources in its plan, as well as requirements to test these Resources. This criterion designates only those generation Blackstart Resources that have been designated as such in the Transmission Operator's restoration plan. The glossary term Blackstart Capability Plan has been retired.~~

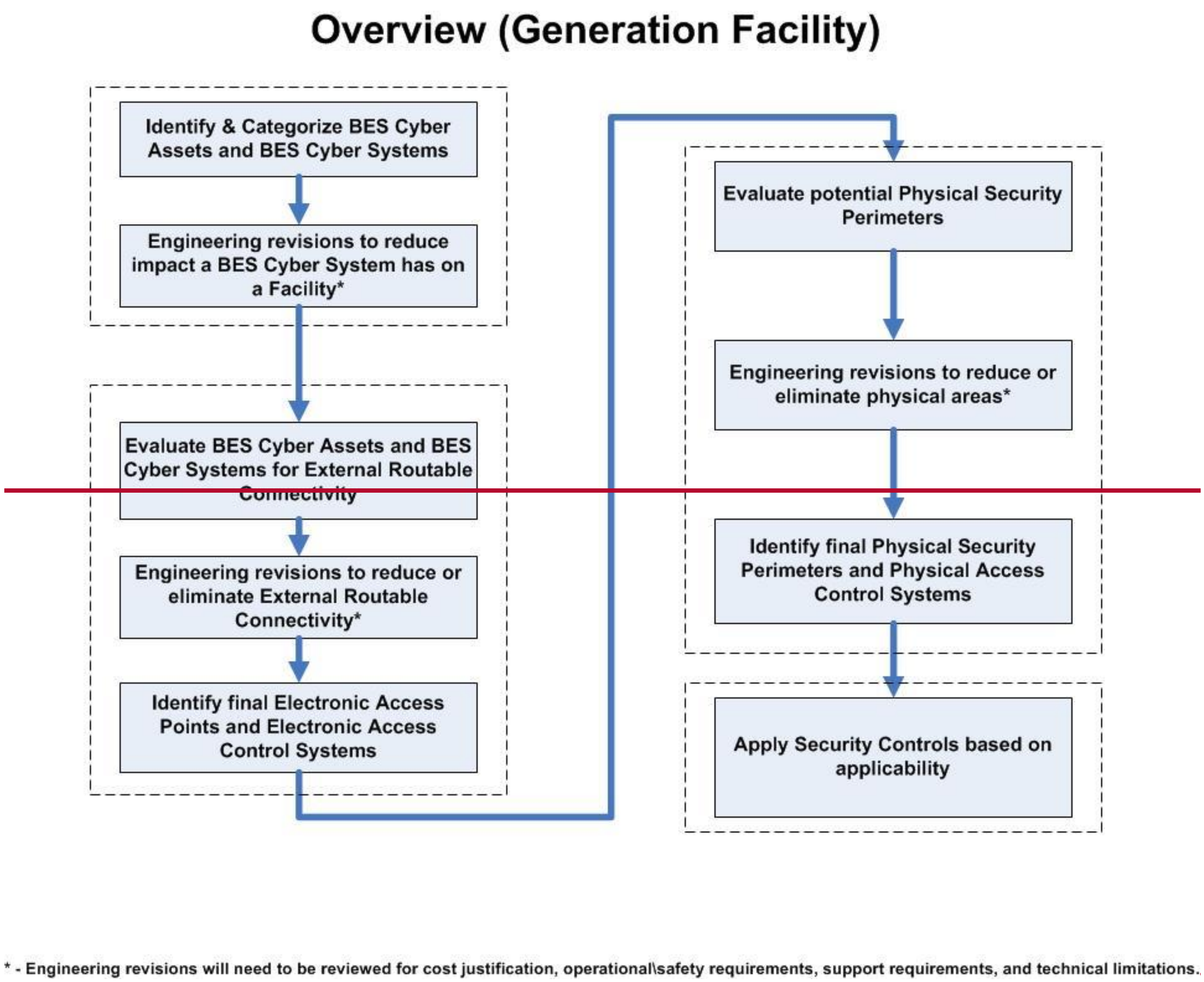
~~Regarding concerns of communication to BES Asset Owners and Operators of their role in the Restoration Plan, Transmission Operators are required in NERC Standard EOP-005-2 to "provide the entities identified in its approved restoration plan with a description of any changes to their roles and specific tasks prior to the implementation date of the plan."~~

- ~~BES Cyber Systems for Facilities and Elements comprising the Cranking Paths and meeting the initial switching requirements from the Blackstart Resource to the first Interconnection point of the generation unit(s) to be started, as identified in the Transmission Operator's restoration plan, default to the category of low impact: however, these systems are explicitly called out to ensure consideration for inclusion in the scope of the version 5 CIP standards. This requirement for inclusion in the scope is sourced from requirements in NERC standard EOP-005-2, which requires the Transmission Operator to include in its Restoration Plan the Cranking Paths and initial switching requirements from the Blackstart Resource and the unit(s) to be started.~~

~~Distribution Providers may note that they may have BES Cyber Systems that must be scoped in if they have Elements listed in the Transmission Operator's Restoration Plan that are components of the Cranking Path.~~

~~**Use Case: CIP Process Flow**~~

~~The following CIP use case process flow for a generator Operator/Owner was provided by a participant in the development of the Version 5 standards and is provided here as an example of a process used to identify and categorize BES Cyber Systems and BES Cyber Assets; review, develop, and implement strategies to mitigate overall risks; and apply applicable security controls.~~



~~Rationale:~~

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

~~Rationale for R1:~~

~~BES Cyber Systems at each site location have varying impact on the reliable operation of the Bulk Electric System. Attachment 1 provides a set of "bright-line" criteria that the Responsible Entity must use to identify these BES Cyber Systems in accordance with the impact on the BES. BES Cyber Systems must be identified and categorized according to their impact so that the appropriate measures can be applied, commensurate with their impact. These impact categories will be the basis for the application of appropriate requirements in CIP-003-CIP-011.~~

~~Rationale for R2:~~

~~The lists required by Requirement R1 are reviewed on a periodic basis to ensure that all BES Cyber Systems required to be categorized have been properly identified and categorized. The miscategorization or non-categorization of a BES Cyber System can lead to the application of inadequate or non-existent cyber security controls that can lead to compromise or misuse that can affect the real-time operation of the BES. The CIP Senior Manager's approval ensures proper oversight of the process by the appropriate Responsible Entity personnel.~~

~~5~~	~~11/26/12~~	~~Adopted by the NERC Board of Trustees.~~	~~Modified to coordinate with other CIP standards and to revise format to use RBS Template.~~
~~5.1~~	~~9/30/13~~	~~Replaced "Devices" with "Systems" in a definition in background section.~~	~~Errata~~
~~5.1~~	~~11/22/13~~	~~FERC Order issued approving CIP-002-5.1.~~	
~~5.1a~~	~~11/02/16~~	~~Adopted by the NERC Board of Trustees.~~	
~~5.1a~~	~~12/14/2016~~	~~FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.~~	

~~Appendix 1~~

~~Requirement Number and Text of Requirement~~
~~CIP-002-5.1, Requirement R1~~ ~~R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of parts 1.1 through 1.3:~~ ~~i. Control Centers and backup Control Centers;~~ ~~ii. Transmission stations and substations;~~ ~~iii. Generation resources;~~ ~~iv. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;~~ ~~v. Special Protection Systems that support the reliable operation of the Bulk Electric System; and~~ ~~vi. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.~~ ~~1.1. Identify each of the high impact BES Cyber Systems according to Attachment 1, Section 1, if any, at each asset;~~ ~~1.2. Identify each of the medium impact BES Cyber Systems according to Attachment 1, Section 2, if any, at each asset; and~~ ~~1.3. Identify each asset that contains a low impact BES Cyber System according to Attachment 1, Section 3, if any (a discrete list of low impact BES Cyber Systems is not required).~~ ~~Attachment 1, Criterion 2.1~~ ~~2. Medium Impact Rating (M)~~ ~~Each BES Cyber System, not included in Section 1 above, associated with any of the following:~~ ~~2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BES Cyber Systems that meet this criterion are those shared BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.~~
~~Questions~~
~~Energy Sector Security Consortium, Inc. (EnergySec) submitted a Request for Interpretation (RFI) seeking clarification of Criterion 2.1 of Attachment 1 in Reliability Standard CIP-002-5.1 regarding the use of the phrase "shared BES Cyber Systems."~~ ~~The Interpretation Drafting Team identified the following questions in the RFI:~~

~~1. Whether the phrase "shared BES Cyber Systems" means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~ ~~2. Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~ ~~3. If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~
~~Responses~~
~~Question 1: Whether the phrase "shared BES Cyber Systems," means that the evaluation for Criterion 2.1 shall be performed individually for each discrete BES Cyber System at a single plant location, or collectively for groups of BES Cyber Systems?~~ ~~The evaluation as to whether a BES Cyber System is shared should be performed individually for each discrete BES Cyber System. In the standard language of CIP-002-5.1, there is no reference to or obligation to group BES Cyber Systems. Requirement R1, part 1.2 states "Identify *each* of the medium impact BES Cyber Systems according to Attachment 1, Section 2…" Further, the preamble of Section 2 of CIP-002-5.1 Attachment 1 states "*Each BES Cyber System*…associated with any of the following [criteria]." (emphasis added)~~ ~~Additionally, the Background section of CIP-002-5.1 states that "[i]t is left up to the Responsible Entity to determine the level of granularity at which to identify a BES Cyber System within the qualifications in the definition of BES Cyber System." The Background section also provides:~~ ~~The Responsible Entity should take into consideration the operational environment and scope of management when defining the BES Cyber System boundary in order to maximize efficiency in secure operations. Defining the boundary too tightly may result in redundant paperwork and authorizations, while defining the boundary too broadly could make the secure operation of the BES Cyber System difficult to monitor and assess.~~ **~~Question 2: Whether the phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple units, or groups of BES Cyber Systems that could collectively impact multiple units?~~** ~~The phrase "shared BES Cyber Systems" refers to discrete BES Cyber Systems that are shared by multiple generation units.~~ ~~The use of the term "shared" is also clarified in the NERC Frequently Asked Questions (FAQ) document issued by NERC Compliance to support implementation of the CIP Reliability Standards. FAQ #49 provides:~~ ~~Shared BES Cyber Systems are those that are associated with any combination of units in a single Interconnection, as referenced in CIP-002-5.1, Attachment 1, impact rating~~

~~criteria 2.1 and 2.2. For criterion 2.1 "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection." For criterion 2.2: "BES Cyber Systems that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR. Also refer to the Lesson Learned for CIP-002-5.1 Requirement R1:~~ **~~Impact Rating of Generation Resource Shared BES Cyber Systems~~** ~~for further information and examples.~~

~~Question 3: If the phrase applies collectively to groups of BES Cyber Systems, what criteria should be used to determine which BES Cyber Systems should be grouped for collective evaluation?~~

~~The phrase applies to each discrete BES Cyber System.~~

Standard Development Timeline

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

Description of Current Draft

This is the final draft of the proposed standard.

Completed Actions	Date
Standards Committee (SC) approved 2016-02 TOCC Standard Authorization Request (SAR) for posting	March 6, 2016
SAR posted for 2016-02 TOCC comment	March 23 – April 21, 2016
SC Accepted the 2016-02 TOCC SAR	July 20, 2016
45-day formal comment period with initial ballot	September 26 – November 9, 2023
45-day formal comment period with additional ballot	April 2 – May 16, 2024
45-day formal comment period with additional ballot	August 29 – October 15, 2024

Anticipated Actions	Date
Final ballot	November 13 – 22, 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):

Control Center – One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

A. Introduction

1. **Title:** Cyber Security — BES Cyber System Categorization
2. **Number:** CIP-002-8
3. **Purpose:** To identify and categorize BES Cyber Systems (BCS) and their associated BES Cyber Assets (BCA) for the application of cyber security requirements commensurate with the adverse impact that loss, compromise, or misuse of those BCS could have on the reliable operation of the Bulk Electric System (BES). Identification and categorization of BCS support appropriate protection against compromises that could lead to misoperation or instability in the BES.
4. **Applicability:**

4.1. Functional Entities: For the purpose of the requirements contained herein, the following list of functional entities will be collectively referred to as "Responsible Entities." For requirements in this standard where a specific functional entity or subset of functional entities are the applicable entity or entities, the functional entity or entities are specified explicitly.

4.1.1. Balancing Authority

4.1.2. Distribution Provider that owns one or more of the following Facilities, systems, and equipment for the protection or restoration of the BES:

4.1.2.1. Each underfrequency load shedding (UFLS) or undervoltage load shedding (UVLS) system that:

4.1.2.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.1.2.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.1.2.2. Each Remedial Action Scheme (RAS) where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.1.2.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.1.3. Generator Operator

4.1.4. Generator Owner

4.1.5. Reliability Coordinator

4.1.6. Transmission Operator

4.1.7. Transmission Owner

4.2. Facilities: For the purpose of the requirements contained herein, the following Facilities, systems, and equipment owned by each Responsible Entity in 4.1 above are those to which these requirements are applicable. For requirements in this standard where a specific type of Facilities, system, or equipment or subset of Facilities, systems, and equipment are applicable, these are specified explicitly.

4.2.1. Distribution Provider: One or more of the following Facilities, systems and equipment owned by the Distribution Provider for the protection or restoration of the BES:

4.2.1.1. Each UFLS or UVLS System that:

4.2.1.1.1. is part of a Load shedding program that is subject to one or more requirements in a NERC or Regional Reliability Standard; and

4.2.1.1.2. performs automatic Load shedding under a common control system owned by the Responsible Entity, without human operator initiation, of 300 MW or more.

4.2.1.2. Each RAS where the RAS is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.3. Each Protection System (excluding UFLS and UVLS) that applies to Transmission where the Protection System is subject to one or more requirements in a NERC or Regional Reliability Standard.

4.2.1.4. Each Cranking Path and group of Elements meeting the initial switching requirements from a Blackstart Resource up to and including the first interconnection point of the starting station service of the next generation unit(s) to be started.

4.2.2. Responsible Entities listed in 4.1 other than Distribution Providers: All BES Facilities.

4.2.3. Exemptions: The following are exempt from Standard CIP-002-8:

4.2.3.1. Cyber Systems at Facilities regulated by the Canadian Nuclear Safety Commission.

4.2.3.2. Cyber Systems associated with communication networks and data communication links between discrete Electronic Security Perimeters (ESPs).

4.2.3.3. Cyber Systems, associated with communication networks and data communication links, between the Cyber Systems providing confidentiality and integrity of an ESP that extends to one or more geographic locations.

4.2.3.4. The systems, structures, and components that are regulated by the Nuclear Regulatory Commission under a cyber security plan pursuant to 10 C.F.R. Section 73.54.

4.2.3.5. For Distribution Providers, the systems and equipment that are not included in section 4.2.1 above.

5. Effective Dates: See Implementation Plan for CIP-002

B. Requirements and Measures

R1. Each Responsible Entity shall implement a process that considers each of the following assets for purposes of Parts 1.1 through 1.3: *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

- **i.** Control Centers and backup Control Centers;
- **ii.** Transmission stations and substations;
- **iii.** Generation resources;
- **iv.** Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements;
- **v.** RAS that support the reliable operation of the BES; and
- **vi.** For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

1.1. Identify each of the high impact BCS according to Attachment 1, Section 1, if any, at each asset;

1.2. Identify each of the medium impact BCS according to Attachment 1, Section 2, if any, at each asset; and

1.3. Identify each asset that contains a low impact BCS according to Attachment 1, Section 3, if any (a discrete list of low impact BCS is not required).

M1. Acceptable evidence includes, but is not limited to, dated electronic or physical lists required by Requirement R1.

R2. Each Responsible Entity shall: *[Violation Risk Factor: Lower] [Time Horizon: Operations Planning]*

2.1 Review the identifications in Requirement R1 and its parts (and update them if there are changes identified) at least once every 15 calendar months, even if it has no identified items in Requirement R1, and

2.2 Have its CIP Senior Manager or delegate approve the identifications required by Requirement R1 at least once every 15 calendar months, even if it has no identified items in Requirement R1.

M2. Acceptable evidence includes, but is not limited to, electronic or physical dated records to demonstrate that the Responsible Entity has reviewed and updated, where necessary, the identifications required in Requirement R1 and its parts, and has had its CIP Senior Manager or delegate approve the identifications required in Requirement R1 and its parts at least once every 15 calendar months, even if it has none identified in Requirement R1 and its parts, as required by Requirement R2.

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.~~, 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 Responsible Entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Responsible Entity shall retain evidence of each requirement in this standard for three calendar years.
- If a Responsible Entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.
- The CEA shall keep the last audit records and all requested and submitted subsequent audit records.

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. ~~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 (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, five percent or fewer BES assets have not been considered according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, 2 or fewer BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer identified BCS have not been categorized	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than five percent but less than or equal to 10 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than two, but fewer than or equal to four BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent but less than or equal to 10 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category;	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 10 percent but less than or equal to 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than four, but fewer than or equal to six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high or medium impact BCS, more than 10 percent but less than or equal to 15 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category;	For Responsible Entities with more than a total of 40 BES assets in Requirement R1, more than 15 percent of BES assets have not been considered, according to Requirement R1; OR For Responsible Entities with a total of 40 or fewer BES assets, more than six BES assets in Requirement R1, have not been considered according to Requirement R1; OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of identified BCS have not been categorized or have been incorrectly categorized at a lower category; OR For Responsible Entities with a total of 100 or fewer high and medium impact

R #	Violation Severity Levels (CIP-002-8)			
	Lower VSL	**Moderate VSL**	**High VSL**	**Severe VSL**
	or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, five percent or fewer high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, five or fewer high or medium BCS have not been identified.	OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than five but less than or equal to 10 identified BES Cyber Systems have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than five percent but less than or equal to 10 percent high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than five but less than or equal to 10 high or medium BCS have not been identified.	OR For Responsible Entities with a total of 100 or fewer high or medium impact BCS, more than 10 but less than or equal to 15 identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 10 percent but less than or equal to 15 percent high or medium BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BCS, more than 10 but less than or equal to 15 high or medium BCS have not been identified.	BCS, more than 15 identified BCS have not been categorized or have been incorrectly categorized at a lower category. OR For Responsible Entities with more than a total of 100 high and medium impact BCS, more than 15 percent of high or medium impact BCS have not been identified; OR For Responsible Entities with a total of 100 or fewer high and medium impact BES Cyber Systems, more than 15 high or medium impact BCS have not been identified.
R2	The Responsible Entity did not complete its review and update for the identification required for Requirement R1	The Responsible Entity did not complete its review and update for the identification required for Requirement R1	The Responsible Entity did not complete its review and update for the identification required for Requirement R1	The Responsible Entity did not complete its review and update for the identification required for Requirement R1

R #	Violation Severity Levels (CIP-002-8)			
	Lower VSL	Moderate VSL	High VSL	Severe VSL
	within 15 calendar months but less than or equal to 16 calendar months of the previous review. (Part 2.1) OR The Responsible Entity did not complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 15 calendar months but less than or equal to 16 calendar months of the previous approval. (Part 2.2)	within 16 calendar months but less than or equal to 17 calendar months of the previous review. (Part2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 16 calendar months but less than or equal to 17 calendar months of the previous approval. (Part 2.2)	within 17 calendar months but less than or equal to 18 calendar months of the previous review. (Part 2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 17 calendar months but less than or equal to 18 calendar months of the previous approval. (Part 2.2)	within 18 calendar months of the previous review. (Part 2.1) OR The Responsible Entity failed to complete its approval of the identifications required by Requirement R1 by the CIP Senior Manager or delegate according to Requirement R2 within 18 calendar months of the previous approval. (Part 2.2)

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

- Implementation Plan for Project 2021-03
- CIP-002-8 Technical Rationale

Version History

Version	Date	Action	Change Tracking
1	1/16/06	R3.2 — Change "Control Center" to "control center."	3/24/06
2	9/30/09	Modifications to clarify the requirements and to bring the compliance elements into conformance with the latest guidelines for developing compliance elements of standards. Removal of reasonable business judgment. Replaced the RRO with the RE as a Responsible Entity. Rewording of Effective Date. Changed compliance monitor to Compliance Enforcement Authority.	
3	12/16/09	Updated version number from -2 to -3. Approved by the NERC Board of Trustees.	Update
3	3/31/10	Approved by FERC.	
4	12/30/10	Modified to add specific criteria for Critical Asset identification.	Update
4	1/24/11	Approved by the NERC Board of Trustees.	Update
5	11/26/12	Adopted by the NERC Board Trustees.	Modified to coordinate with other CIP standards and to revise format to use RBS Template.
5.1	9/30/13	Replaced "Devices" with "Systems" in a definition in background section.	Errata
5.1	11/22/13	FERC Order issued approving CIP-002-5.1.	
5.1a	11/02/16	Adopted by the NERC Board of Trustees.	
5.1a	12/14/2016	FERC letter Order approving CIP-002-5.1a. Docket No. RD17-2-000.	
6	5/14/2020	Adopted by the NERC Board of Trustees.	Modified Criterion 2.12.
7	TBD	Virtualization Modifications	

Version	Date	Action	Change Tracking
7	5/9/2024	Adopted by the NERC Board of Trustees.	
8	TBD	Transmission Owners Control Centers Update	

Attachment 1 – Impact Rating Criteria

Impact Rating Criteria

The criteria defined in Attachment 1 do not constitute stand-alone compliance requirements, but are criteria characterizing the level of impact and are referenced by requirements.

1. **High impact rating**

   Each BCS used by and located at any of the following:

   1.1. For Reliability Coordinators, each Control Center or backup Control Center used to perform the reliability tasks of the Reliability Coordinator.

   1.2. For Balancing Authorities, each Control Center or backup Control Center used to perform the reliability tasks of the Balancing Authority for: 1) generation equal to or greater than an aggregate of 3000 MW in a single Interconnection, or 2) one or more of the assets that meet criterion 2.3, 2.6, or 2.9.

   1.3. For Transmission Operators and Transmission Owners, each Control Center or backup Control Center for one or more of the assets that meet criterion 2.2, 2.4, 2.5, 2.7, 2.8, 2.9, or 2.10.

   1.4 For Generator Operators, each Control Center or backup Control Center used to perform the reliability tasks of the Generator Operator for one or more of the assets that meet criterion 2.1, 2.3, 2.6, or 2.9.

2. **Medium impact rating**

   Each BCS, not included in Section 1 above, associated with any of the following:

   2.1. Commissioned generation, by each group of generating units at a single plant location, with an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection. For each group of generating units, the only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of units that in aggregate equal or exceed 1500 MW in a single Interconnection.

   2.2. Each BES reactive resource or group of resources at a single location (excluding generation Facilities) with an aggregate maximum Reactive Power nameplate rating of 1000 MVAR or greater (excluding those at generation Facilities). The only BCS that meet this criterion are each discrete shared BCS that could, within 15 minutes, adversely impact the reliable operation of any combination of resources that in aggregate equal or exceed 1000 MVAR.

   2.3. Each generation Facility that its Planning Coordinator or Transmission Planner designates, and informs the Generator Owner or Generator Operator, as necessary to avoid an Adverse Reliability Impact in the planning horizon of more than one year.

   2.4. Transmission Facilities operated at 500 kV or higher. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

   2.5. Transmission Facilities that are operating between 200 kV and 499 kV at a single station or substation, where the station or substation is connected at 200 kV or higher

voltages to three or more other Transmission stations or substations and has an "aggregate weighted value" exceeding 3000 according to the table below. The "aggregate weighted value" for a single station or substation is determined by summing the "weight value per line" shown in the table below for each incoming and each outgoing BES Transmission Line that is connected to another Transmission station or substation. For the purpose of this criterion, the collector bus for a generation plant is not considered a Transmission Facility, but is part of the generation interconnection Facility.

Voltage Value of a Line	Weight Value per Line
less than 200 kV (not applicable)	(not applicable)
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

2.6. Generation at a single plant location or Transmission Facilities at a single station or substation location that are identified by its Reliability Coordinator, Planning Coordinator, or Transmission Planner as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.

2.7. Transmission Facilities identified as essential to meeting Nuclear Plant Interface Requirements.

2.8. Transmission Facilities, including generation interconnection Facilities, providing the generation interconnection required to connect generator output to the Transmission Systems that, if destroyed, degraded, misused, or otherwise rendered unavailable, would result in the loss of the generation Facilities identified by any Generator Owner as a result of its application of Attachment 1, criterion 2.1 or 2.3.

2.9. Each RAS or automated switching System that operates BES Elements, that, if destroyed, degraded, misused, or otherwise rendered unavailable, would cause one or more IROLs violations for failure to operate as designed or cause a reduction in one or more IROLs if destroyed, degraded, misused, or otherwise rendered unavailable.

2.10. Each system or group of Elements that performs automatic Load shedding under a common control system, without human operator initiation, of 300 MW or more implementing UVLS or UFLS under a load shedding program that is subject to one or more requirements in a NERC or regional reliability standard.

2.11. For Generator Operators, each Control Center or backup Control Center used to perform the reliability tasks of the Generator Operator for an aggregate highest rated net Real Power capability of the preceding 12 calendar months equal to or exceeding 1500 MW in a single Interconnection.

2.12. For Transmission Operators and Transmission Owners, each Control Center or backup Control Center with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value

per BES Transmission Line," shown in the table below, that are~~is~~ monitored and controlled by the Control Center or backup Control Center ~~shown in the table below~~. Include each BES Transmission Line that is connected between two or more Transmission stations or substations.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line
<100 kV	100
100 kV to 199 kV	250
200 kV to 299 kV	700
300 kV to 499 kV	1300
500 kV and above	0 (N/A)

Exclusion:
Provided that the "aggregate weighted value" calculated according to the table above is less than 12000, a Transmission Operator or a Transmission Owner may exclude the BES Transmission Lines that are contained in a single group of contiguous Elements from their "aggregate weighted value" calculation, where a group of contiguous Elements is defined as:

- a group of contiguous Elements emanating from multiple points of connection at 69 kV or higher;
- that are operated at less than 300 kV; and
- where the gross export does not exceed 75 MWh during non-Energy Emergency Alert conditions. The gross export is based on the hourly integrated values of the preceding 12 calendar months.

2.13. For Balancing Authorities, each Control Center or backup Control Center used to perform the reliability tasks of the Balancing Authority for generation equal to or greater than an aggregate of 1500 MW in a single Interconnection.

3. Low impact rating

BCS not included in Sections 1 or 2 above that are associated with any of the following assets and that meet the applicability qualifications in Section 4 - Applicability, part 4.2 – Facilities, of this standard:

3.1. Control Centers and backup Control Centers.

3.2. Transmission stations and substations.

3.3. Generation resources.

3.4. Systems and facilities critical to system restoration, including Blackstart Resources and Cranking Paths and initial switching requirements.

3.5. RAS that support the reliable operation of the BES.

3.6. For Distribution Providers, Protection Systems specified in Applicability section 4.2.1 above.

Implementation Plan

Project 2021-03 CIP-002 | Reliability Standard CIP-002-8

Applicable Standard(s)

- Reliability Standard CIP-002-8 – Cyber Security - BES Cyber System Categorization

Requested Retirement(s)

- Reliability Standard CIP-002-7 – Cyber Security - BES Cyber System Categorization

Prerequisite Definition

This definition must be approved before the Applicable Standard becomes effective:

- Cyber System[1]

Applicable Entities

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

Modified 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 Modified Definition

Control Center - One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real-time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator

[1] The new term Cyber System was developed as part of Project 2016-02 – Modifications to CIP Standards.

for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

OR

One or more facilities of a Transmission Owner that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers, and excluding field Cyber Assets used for telemetry.

Background

Project 2021-03 includes revisions to the Control Center definition and CIP-002 Attachment 1. The proposed revisions to the Control Center definition are intended to ensure Transmission Owners correctly identify their Control Centers. The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers that have the capability to control transmission Facilities at two or more locations in real-time using SCADA. These modifications resulted from recommendations from the CIP-002 Transmission Owner Control Center Field Test Report.[2]

General Considerations

This Implementation Plan includes phased-in implementation dates for CIP-002-8, Attachment 1. The phased-in implementation dates allow Responsible Entities[3] a longer implementation period if the revisions to the Criterion would result in a higher impact level categorization of a BES Cyber System.

Effective Date and Phased-In Compliance Dates

The effective date for proposed Reliability Standard CIP-002-8 and the modified definition is provided below. Where the drafting team identified the need for a longer implementation period for compliance with a particular section of the proposed Reliability Standard (i.e., an entire Requirement or a portion of it), the additional time for compliance with that section is specified below. The phased-in implementation date for those particular sections is the date that Responsible 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 CIP-002-8 and Control Center Definition

Where approval by an applicable governmental authority is required, the standard and Control Center definition shall become effective on the later of 1) the effective date of CIP-002-7; or 2) the first day of the first calendar quarter that is three (3) months after the effective date of the applicable governmental authority's order approving CIP-002-8, or as otherwise provided for by the applicable governmental authority.

[2] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf

[3] As used in the CIP Reliability Standards, a Responsible Entity refers to a registered entity responsible for the implementation of and compliance with a particular requirement.

Where approval by an applicable governmental authority is not required, the standard and Control Center definition shall become effective on the later of 1) the effective date of CIP-002-7; or 2) the first day of the first calendar quarter that is three (3) months after the date CIP-002-8 is adopted by the NERC Board of Trustees, or as otherwise provided for in that jurisdiction.

Compliance Dates for CIP-002-8

Initial Performance of Periodic Requirements

Responsible Entities shall initially comply with the periodic requirements in CIP-002-8, Requirement R2 within 15 calendar months of their last performance of Requirement R2 under the version of CIP-002 immediately effective prior to CIP-002-8.

Phased-in Implementation Date for CIP-002-8, Requirement R1, Attachment 1 Criterion 2.12

If the revisions to Criteria 2.12 of Attachment 1 to CIP-002-8 result in a higher impact level categorization of a BES Cyber System, the Responsible Entity shall not be required to identify that BES Cyber System as that higher categorization nor apply the requirements throughout the CIP standards applicable to that higher categorization until 24 months after the effective date of CIP- 002-8. This would be considered a planned change, such that the Responsible Entity is expected to comply with the higher categorization 24 months after the effective date of CIP-002-8 as opposed to further extensions that would be allowable for an unplanned change. Until that time, the Responsible Entity shall continue to identify that BES Cyber System consistent with its existing categorization under CIP-002-5.1a or CIP-002-7, Requirement R1, Part 1.3, whichever version of CIP-002 is enforceable immediately prior to the effective date of CIP-002-8.

Planned or Unplanned Changes

Planned Changes

Planned changes refer to any changes of the electric system or a BES Cyber System which were planned and implemented by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-8, Requirement R2.

For example, if an automation modernization activity is performed at a transmission substation, whereby Cyber Assets are installed that meet the criteria in CIP-002-8, Attachment 1, then the new BES Cyber System has been implemented as a result of a planned change, and must, therefore, be in compliance with the CIP Cyber Security Standards upon the commissioning of the modernized transmission substation.

For planned changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control or Monitoring Systems and Protected Cyber Assets, etc. For periodic requirements in Reliability Standards CIP-004 through CIP-011, the period within which Responsible Entities must initially comply begins on the update of the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control or Monitoring Systems and Protected Cyber Assets.

Unplanned Changes

Unplanned changes refer to any changes of the electric system or a BES Cyber System which were not planned by the Responsible Entity and subsequently identified through the annual assessment under CIP-002-8, Requirement R2.

For example, consider the scenario where a particular BES Cyber System at a transmission substation does not meet the criteria in CIP-002-8, Attachment 1, then an action is performed outside of that particular transmission substation; such as, a transmission line is constructed or retired, a generation plant is modified, changing its rated output, and that unchanged BES Cyber System may become a medium impact BES Cyber System based on the CIP-002-8, Attachment 1, criteria.

For unplanned changes resulting in a higher categorization, the Responsible Entity shall comply with all applicable requirements in the CIP Cyber Security Standards, according to the following timelines, following the identification and categorization of the affected BES Cyber System and any applicable and associated Physical Access Control Systems, Electronic Access Control or Monitoring Systems and Protected Cyber Assets, etc. For periodic requirements in Reliability Standards CIP-004 through CIP-011, the period within which Responsible Entities must initially comply begins at the end of the timelines listed below.

Scenario of Unplanned Changes After the Effective Date	Compliance Implementation
New high impact BES Cyber System	12 months
New medium impact BES Cyber System	12 months
Newly categorized high impact BES Cyber System from medium impact BES Cyber System	12 months for requirements not applicable to Medium impact BES Cyber Systems
Newly categorized medium impact BES Cyber System	12 months
Responsible Entity identifies its first high impact or medium impact BES Cyber System (i.e., the Responsible Entity previously had no BES Cyber Systems categorized as high impact or medium impact according to the CIP-002 identification and categorization processes)	24 months

Retirement Date

Reliability Standard CIP-002-7

Reliability Standard CIP-002-7 shall be retired immediately prior to the effective date of Reliability Standard CIP-002-8 in the particular jurisdiction in which the revised standard is becoming effective.

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Technical Rationale

Project 2021-03 CIP-002 | Reliability Standard CIP-002-8

CIP-002-8 – Cyber Security – BES Cyber System Categorization and Control Center Definition

Introduction

This document explains the technical rationale and justification for the proposed revisions to the Control Center Definition and Reliability Standard CIP-002-8. It provides stakeholders and the ERO Enterprise with a description of the technical requirements in the Reliability Standard. These are not Reliability Standards and should not be considered mandatory and enforceable.

Updates to this document include the Project 2021-03 CIP-002 Drafting Team's (DT's) intent in drafting changes to the requirements and definition.

Overview

Project 2021-03 proposes revisions to the Control Center definition and CIP-002-8 criterion 2.12 in Attachment 1. CIP-002-8 provides "bright-line" criteria for applicable Responsible Entities to categorize their BES Cyber Systems (BCS) based on the impact to their associated Facilities, systems, and equipment, which, if destroyed, degraded, misused, or otherwise rendered unavailable, would affect the reliable operation of the Bulk Electric System (BES). The proposed revisions to Attachment 1 address the categorization of Transmission Owner Control Centers (TOCCs) performing the functional obligations of a Transmission Operator (TOP), specifically those that meet medium impact criteria, and clarifying the language scope of "perform the functional obligations of" throughout the Attachment 1 criteria.

Rationale for Control Center Definition Modification

Rationale for Proposing Modifications to the Control Center Definition

During the CIP-002 TOCC Field Test[1], it was found that many Transmission Owners (TO)s struggled with how to interpret the Control Center definition. While the current Control Center definition does not specifically identify TOs, a TO may have a Control Center through its ability to monitor and control the BES in real-time to perform the reliability tasks of a TOP. This struggle surfaced in the following three manners:

- Lack of a common understanding of the term "control" versus "authority" as it relates to TOPs
- Lack of a common understanding of the term "perform the functional obligations of the TOP" as stated in Attachment 1 of CIP-002-5.1a.
- Lack of a common understanding of the term "associated data centers" versus TO BES Cyber Assets capable of controlling transmission Facilities.

Modifications to the definition have been proposed to eliminate ambiguity.

[1] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

Applicable Control Center Entities

Considering industry comments, the Control Center definition for Reliability Coordinator (RC), Balancing Authority (BA), TOP, and Generator Operator (GOP) was not revised. The industry felt the Control Center and data center definitions for these registered entities were well understood and is structured to explicitly identify the four different types of registered entities have gone through the scrutiny of compliance monitoring. Thus, no changes were made for these four registered entities that could have a Control Center.

The Control Center definition was expanded to incorporate the TO as follows: “One or more facilities of a TO that have the capability to control transmission Facilities at two or more locations in real-time using Supervisory Control and Data Acquisition (SCADA), including their associated data centers and excluding field Cyber Assets used for telemetry.”

A TO is considered to have a Control Center if it has the capability to control transmission Facilities at two or more locations using SCADA. The concept of ‘capability to control using SCADA’ is specifically used to differentiate between control and monitor functions – i.e., clarify that a facility used by a TO to monitor Facilities without any capability to electronically control those Facilities using a SCADA system does not fall within the Control Center definition. For example, a TO who issues verbal instructions to field switching personnel but who does not have the ‘capability to control using SCADA’ would not be considered to have a Control Center.

The use of the NERC defined term “SCADA” is intended to exclude Cyber Assets used at a relay maintenance office to change relays setting, which may allow the capability to remotely operate a breaker. These Cyber Assets would not be considered a Control Center but may be required to be protected under other cyber security categories. Likewise, the use of the NERC defined term “SCADA” is intended to exclude Cyber Assets and Human Machine Interface (HMI) located at substations that have the capability to monitor and control transmission Facilities locally at the substation. These Cyber Assets would not be considered a Control Center but may be required to be protected under other cyber security categories.

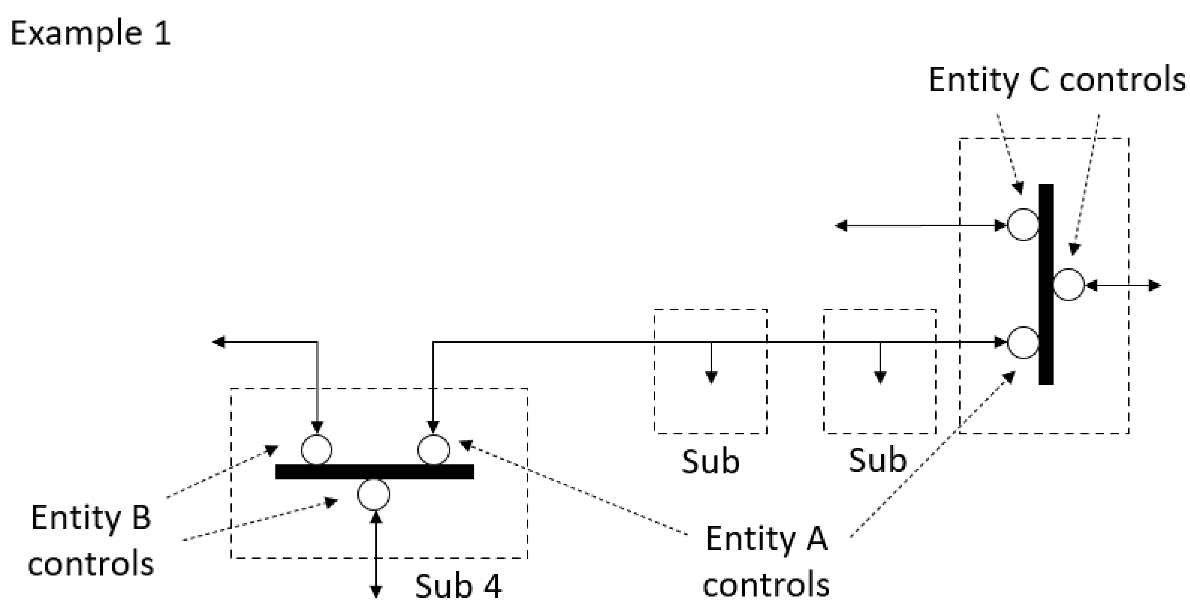
Because a SCADA system may include telemetry per the NERC defined term, the DT has crafted language to specifically exclude field Cyber Assets used for telemetry from being part of the Control Center and associated impact level determination. The impact level of field Cyber Assets, including telemetry, should be evaluated based on the location and associated impact level contained in Attachment 1.

The part of the Control Center definition that is applicable to the TO is not tied to the functional obligations of the TOP, nor is it tied to any TOP reliability tasks. Rather, it is tied to having a BES Cyber System or BES Cyber Asset, i.e., a SCADA system with the capability to control. It does not matter if the TO has a reliability task with pre-authorized authority from the TOP to control transmission Facilities or only receives operating instructions from the TOP. The cyber security risk that must be protected is access to the BES Cyber System or BES Cyber Asset(s), i.e., SCADA system that are able to control the transmission Facility.

When considering the language “transmission Facilities at two or more locations” and “generation Facilities at two or more locations,” it is generally expected that the Facilities will have separate street addresses. Facilities located at a single street address would be associated with a single location. An entity must have more than one Facility and must have Facilities at two or more locations in order to have "transmission Facilities at two or more locations" or "generation Facilities at two or more locations."

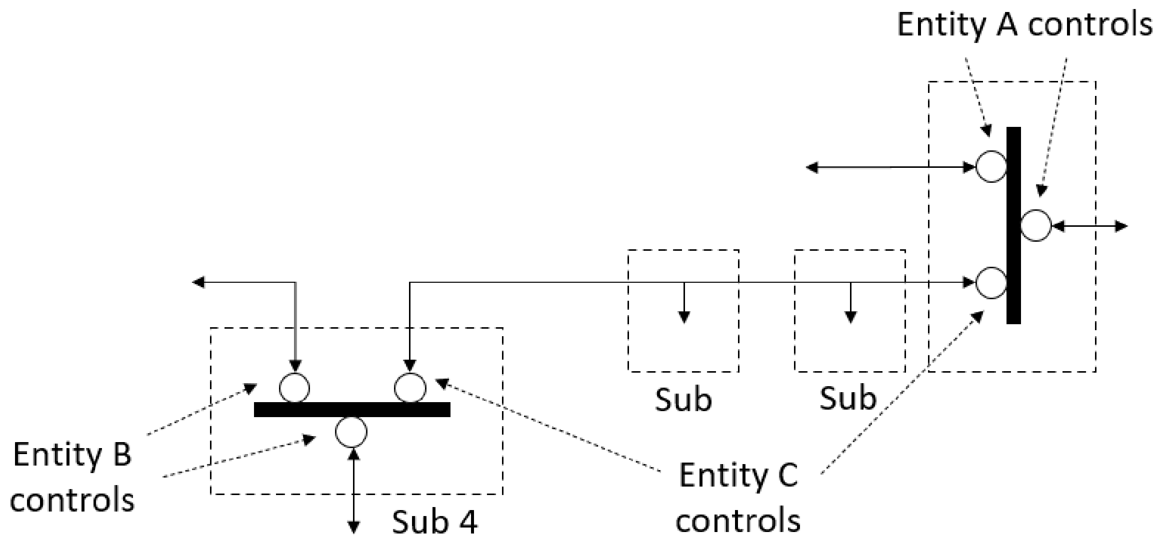
With respect to Transmission Owners who have facilities that are capable of controlling High Voltage Direct Current (HVDC) Facilities, each Responsible Entity will need to engage with their Regional Entity in order to determine how the language "transmission Facilities at two or more locations" should be applied based on the specific configuration. The current definition has not changed for Transmission Operators, and thus there is no expected change in applicability to classification of their operated HVDC Facilities.

The following examples differentiate between a single transmission Facility and two or more transmission Facilities at one location.

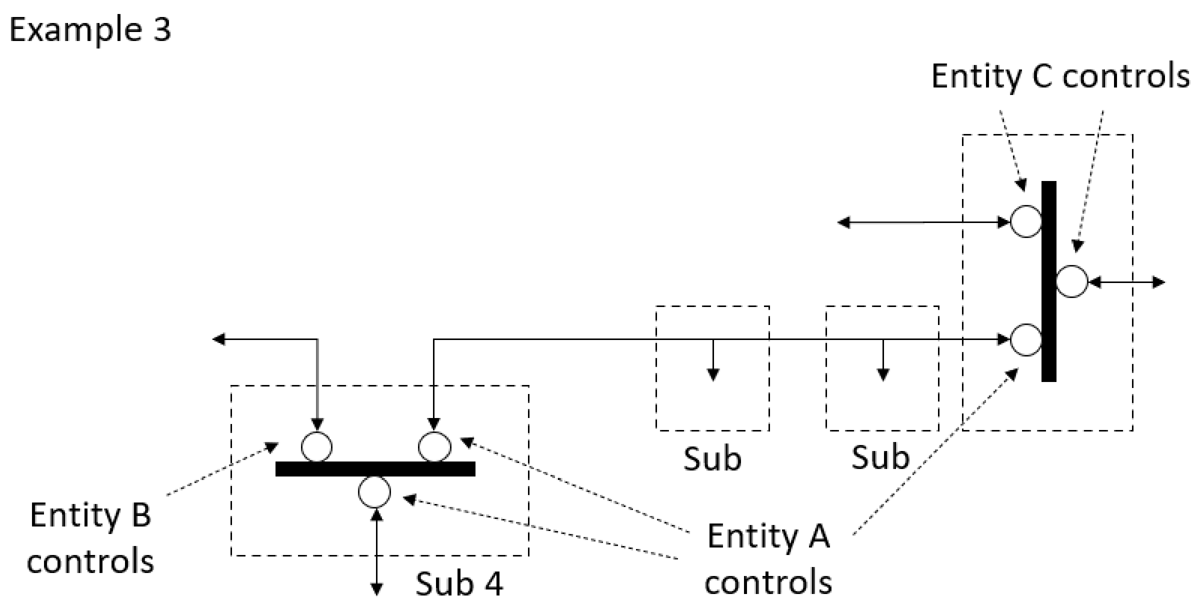


In Example 1, Entity A has control of breakers at both ends of a Transmission Line, which constitutes a transmission Facility. Because Entity A controls a single transmission Facility at 2 locations, Entity A does not meet the TO or TOP Control Center definition.

Example 2



In Example 2, Entity A has control of breakers at one end of two transmission Facilities, but at a single location. Because Entity A controls two transmission Facilities at only 1 location, Entity A does not meet the TO or TOP Control Center definition.



In Example 3, Entity A has control of breakers at one end of two transmission Facilities and a breaker at different location. Because Entity A controls two transmission Facilities at 2 locations, Entity A does meet the TO or TOP Control Center definition.

Associated Data Centers

The Control Center definition includes the phrase "associated data centers". This phrasing is intended to ensure that Cyber Assets that are not co-located in the facilities that host operating personnel are included in the Control Center definition, and are thus included in the process of identifying and categorizing BCS.

Industry comments received during the standard drafting process indicate that lack of a NERC definition for data center has not been an issue in applying the Control Center definition. Therefore, the term "associated data center" was retained in the revised definition.

Rationale for CIP-002-8 Attachment 1 Modifications

Removal of Functional Obligation Language

Language throughout Attachment 1 of CIP-002-8 that referred to the "functional obligations" of the different Registered Entities has been replaced with references to the reliability tasks performed by those same Registered Entities. This change was incorporated given that the NERC Functional Model is no longer being actively maintained and to align with the language used in the Control Center definition. It also resolves an issue whereby an entity may be identified as performing functional obligations even though that entity is not currently registered with NERC. The proposed modifications ensure that the responsibility for entity registration precedes enforcement of CIP-002-8. Usage of 'reliability task" is to provide flexibility to an entity when referring to activities performed by that entity to ensure resource adequacy and operational reliability of BES Elements and Facilities. Additional information on the BES reliability operating services that may be useful to entities when they are defining their reliability tasks can be found in the technical rationale document associated with CIP-002-7. Each entity is ultimately responsible for reviewing their obligations under the NERC Standards to identify their reliability tasks.

Calculating an Aggregate Weighted Value per Criteria 2.12

The total aggregate weighted value is used to account for the impact on the BES. The 6,000 aggregate weighted value threshold defined in criterion 2.12 provides sufficient differentiation for medium and low impact BCS associated with Control Centers that are operated by a registered TOP or owned by a registered TO. DT analysis of data obtained from the CIP-002 Transmission Owner Control Center Field Test[2] validated that those facilities that may have significant impact are categorized at an appropriate level commensurate with the associated risk.

The total aggregate weighted value of 6,000 was derived based on an entity with no single station or substation that meets criterion 2.5, but who has the capability or authority to control BES Transmission Lines with the equivalent weight of two stations or substations whose BCS would be classified as medium impact per criterion 2.5. This is ultimately derived from the "two or more locations" criteria that is documented in the Control Center definition.

For consistency with the existing Attachment 1 criteria, the weighted values for the various voltage classes of BES Transmission Lines were selected to align with the existing approved values in criterion 2.5. For BES Transmission Lines 200 kV to 299 kV and for BES Transmission Lines 300 kV to 499 kV, the weighted values per line are 700 and 1300, respectively. Similar average MVA line loadings based on kV rating were calculated for BES Transmission Lines less than 100 kV and for BES Transmission Lines 100 kV to 199 kV using Appendix A of NERC's Severity Risk Index Enhancements Report which result in weighted values of 100 and 250, respectively.

BES Transmission Lines that are energized at voltages of 500 kV and above have no contribution to the aggregated weighted value given that criterion 2.4 already includes BCS for any transmission Facilities at substations that are operated at 500 kV or higher as medium impact. Further, criterion 1.3 includes the BCS used by and located at Control Centers or backup Control Centers that monitor and control any BES Transmission Lines at substations that are operated at 500 kV or higher as high impact. During industry commenting periods, the drafting team received many inquiries into the use of zero (0) in the table for criterion 2.12, which was originally proposed to remain consistent with existing criteria 2.5. Pursuant to these comments, the DT elected to use "0 (N/A)" in both criterion 2.5 and criterion 2.12 to make it clear that these lines are not relevant for inclusion in the aggregate weighted value calculation.

For the purpose of identifying a Responsible Entity's BES Transmission Lines, a Transmission Line is typically defined by the Protection System(s) that would be used to isolate faults on the Transmission Line – which is generally defined by a boundary of fault interrupting devices (e.g., breakers) that are controlled by the line's Protection System(s). Transmission Lines can be single-ended, two-ended or three-ended.

In the terms of applicable BES Transmission Lines, the following should be considered:

- All BES Transmission Lines that are energized at voltages less than 100 kV, are monitored and controlled by a Control Center, and have been specifically designated as part of the BES via the

[2] The final field test report is available at https://www.nerc.com/pa/Stand/Project202103_CIP002_Transmission_Owner_Control_Ce/2021-03_CIP-002_TOCC_Field_Test_Final_Report_01262023.pdf.

NERC Rules of Procedure (ROP) Exception Process.

- All BES Transmission Lines that are energized at voltages between 100 kV and 499 kV, connect to another Transmission station or substation, and are monitored and controlled by a Control Center. This includes BES Transmission Lines that connect to neighboring entities.
- Multiple-point BES Transmission Lines (e.g., two-ended or three-ended lines) are considered to contribute a single weight value per line. For any fault on the line, all line breakers located at the terminals are expected to operate to clear the fault. For example, a single 230 kV three-ended line would contribute an aggregate weighted value of 700 based on the criterion 2.12 table.

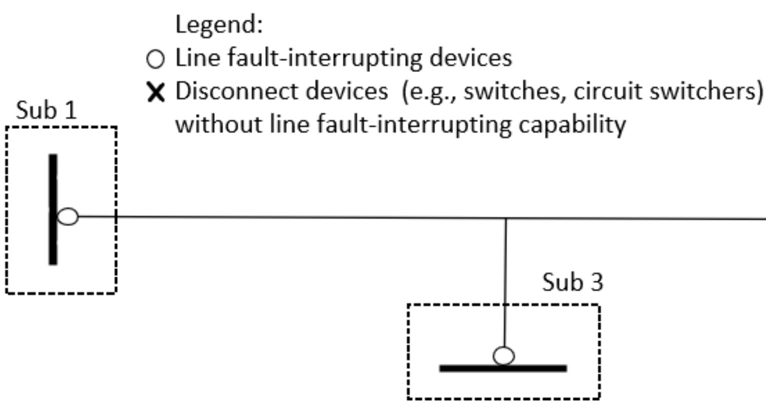


Figure 1: A 230 kV three-terminal Transmission Line contributes an aggregate weighted value of 700

- Multiple-taps BES Transmission Lines (including various implementations such as loop-in-loop-out) are considered to contribute a single weight value per line. For example, a two-ended 230 kV line with two substations tapped on the line where the substations do not have any 230 kV line fault-interrupting devices would contribute an aggregate weighted value of 700 based on the criterion 2.12 table.

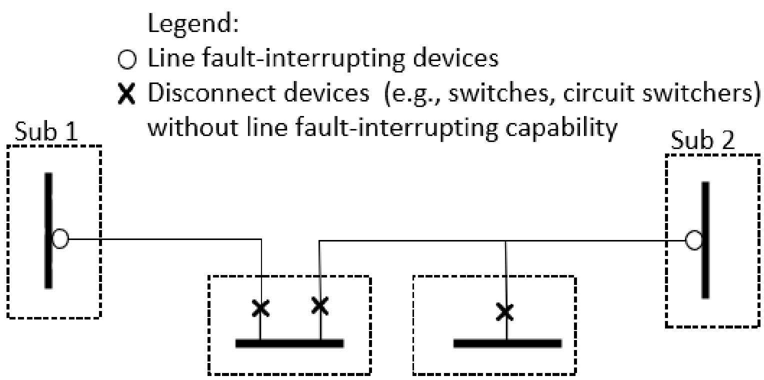


Figure 2: A 230 kV two-terminal Transmission Line with two tapped substations contributes an aggregate weighted value of 700

- Multiple lines between two transmission stations or substations are considered to contribute multiple weight values per line. For example, two two-ended 345 kV lines that connect between the same two transmission stations or substations would contribute an aggregate weighted value of 2,600 based on the criterion 2.12 table.

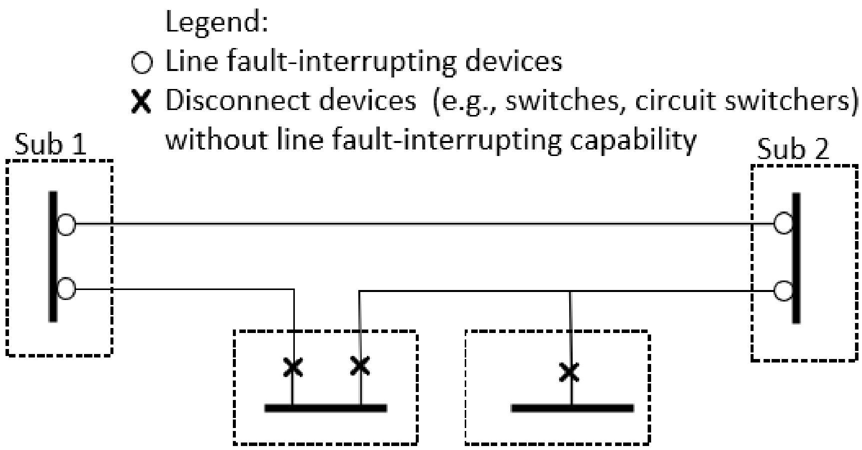


Figure 3: Two 345 kV two-terminal Transmission Lines that connect between the same two Transmission stations or substations contribute an aggregate weighted value of 2,600

Applying the Exclusion Clause per Criterion 2.12

An exclusion clause has been provided to allow Responsible Entities to appropriately categorize their BES Cyber Assets at Control Centers at a level that is commensurate with the associated risk for local systems having limited flow-through or generation export, and are primarily designed to serve load.

The exclusion clause applies to TOPs and TOs where the initial calculated aggregated weighted value (AWV) is less than 12,000. In such cases, the TOP/TO may calculate a revised AWV that excludes those BES Transmission Lines that are contained in a single group of contiguous Elements (GCE[3]) operated at or greater than 69 kV but less than 300 kV, as defined by the Responsible Entity. The hourly integrated gross export from the GCE must not exceed 75 MWh during the preceding 12 calendar months during non-Energy Emergency Alert (EEA) conditions. Gross exports from the GCE during an EEA condition that exceed 75 MWh are allowed to enable the Responsible Entity to provide support to neighboring entities during EEA conditions without any compliance impact.

Entities that choose to pursue an exclusion under criterion 2.12 are responsible for documenting the process whereby they will calculate the hourly integrated gross export from the defined GCE. The concept of an hourly integrated value was selected to avoid requiring entities to use an instantaneous value. There is no requirement that entities install meters specifically for the purpose of calculating the hourly integrated gross export; however, they may do so if they choose. Alternatively, entities may choose to use SCADA data for the purposes of calculating the hourly integrated value.

An entity is responsible to clearly define the GCE and to monitor flows across the interfacing equipment

[3] The concept of a "group of contiguous Elements" will be referred to as a GCE throughout the remainder of this document for simplicity. The acronym is solely used in this document and is not included as a defined term in the NERC Glossary of Terms.

in order to demonstrate compliance with CIP-002. Interfacing equipment is not limited to BES Transmission Lines, provided that the entity is able to collect the necessary data to demonstrate gross export from the GCE remains below 75 MWh. The GCE may contain Elements that the Control Center is not able to control, provided that the GCE boundary encompasses a transmission network that is primarily designed to serve load. The GCE specifically excludes Transmission Lines 300kV and above, as they are generally intended for the bulk transfer of power and not for local load serving purposes. A restriction to allow the responsible entity to define only one GCE is established to prohibit the ability of the entity to segment off multiple areas within a larger geographic area.

An initial calculated AWV of 12,000 is established to avoid application of the exclusion to large control areas. The AWV of 12,000 corresponds to an entity with no single station or substation that meets criterion 2.5, but who has the capability or authority to control BES Transmission Lines with the equivalent weight of four stations or substations whose BES Cyber Systems would be classified as medium impact per criterion 2.5. During the Field Test performed by the DT, entities with AWV between 500 and 11,300 were evaluated and no reliability risks to the BES were identified for any entities.

The bright line of 75 MWh is selected to align with pre-existing criteria including (1) the registration criteria for a Distribution Provider (DP) and (2) the registration criteria for a GO. Establishing a threshold is intended to differentiate between non-impactful load serving areas and areas that are more likely to have an impact on the interconnected BES. It was selected to be conservative and is below other established thresholds such as the reporting requirement for uncontrolled loss of firm load resulting from a BES Emergency and firm load shedding resulting from a BES Emergency as documented in EOP-004. EEA conditions were specifically excluded to ensure a Responsible Entity is not disincentivized from providing all available assistance during emergency conditions due to future compliance considerations.

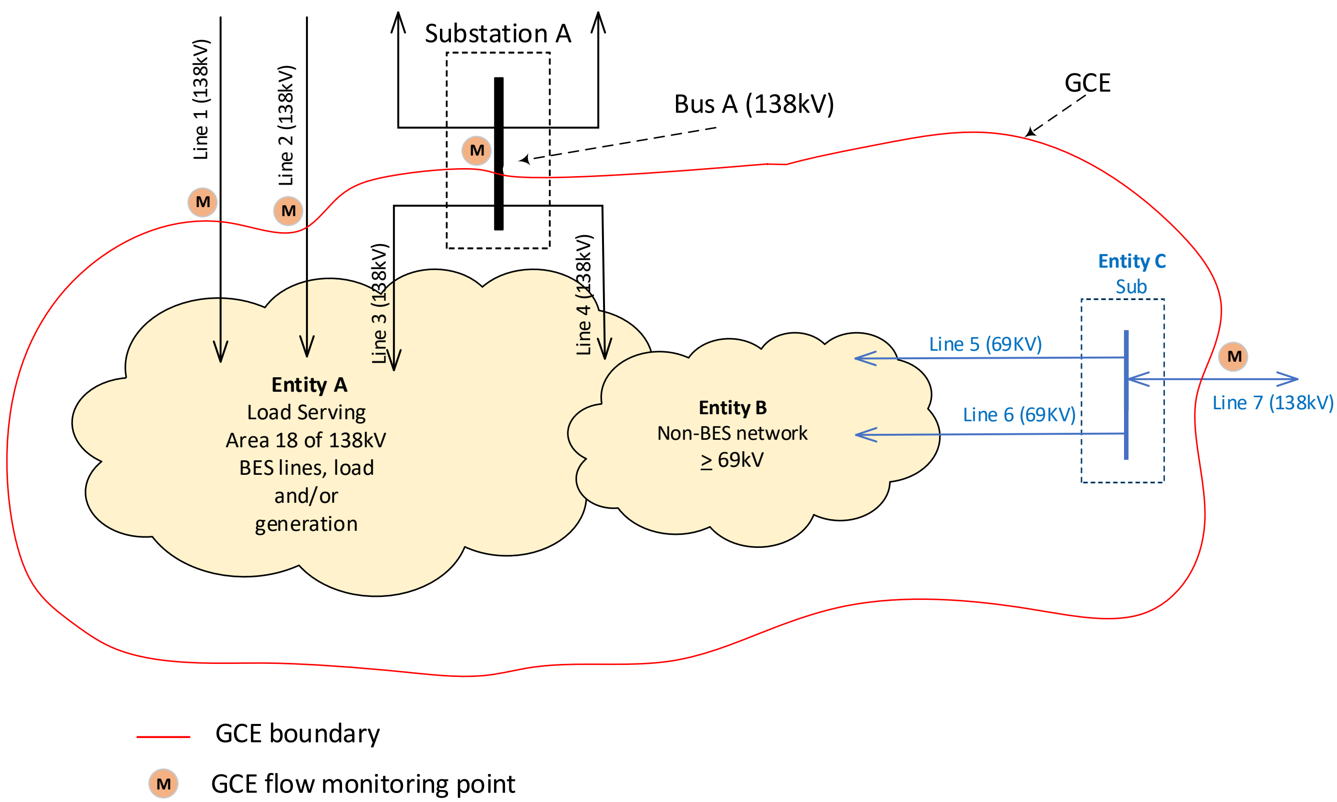
The DT has intentionally constructed the exclusion clause to require an entity to measure gross export from their defined GCE. This accounts for both generation output and flow-through the GCE. It ensures that an entity is unable to define a GCE that contains significant generation that supports the BES or with significant flow-through that impacts the BES.

GCE Example

The GCE must be a contiguous system. It may contain non-BES assets that are operated at 69kV or above and it may contain assets owned/operated by another entity. In the event that a non-BES element is part of the GCE interface, it will need to be included in the gross export calculation.

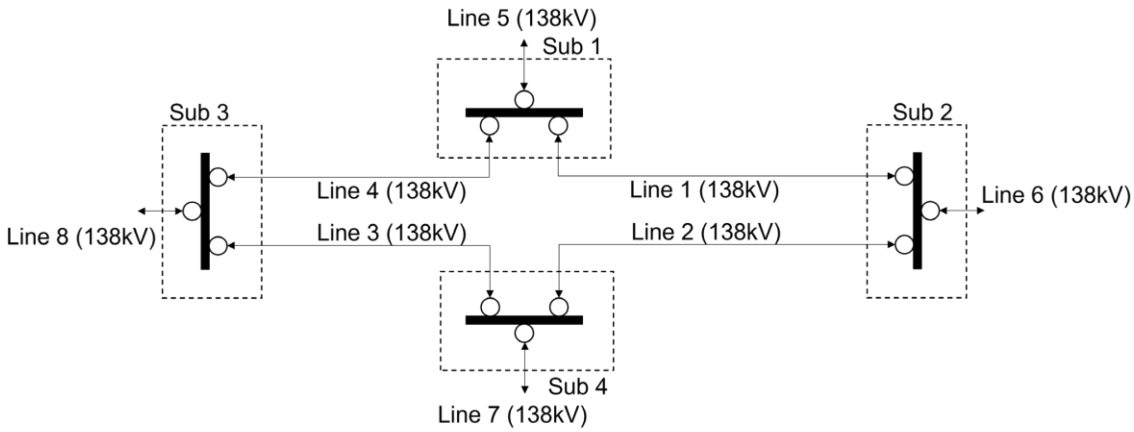
In this example, Entity A defines a GCE that contains all equipment shown in the red boundary below. The GCE interface consists of the flow through Bus A, Line 1, Line 2, and Line 7. The GCE contains equipment owned and operated by Entities A, B and C. To demonstrate compliance with the exclusion clause, Entity A must be able to obtain the necessary data from Entity C for Line 7 to calculate the gross export to demonstrate compliance with CIP-002. The entity must also be able to determine the relevant flow through Bus A, Line 1, Line 2, and Line 7 to demonstrate that gross export from the GCE does not exceed 75 MWh.

In this particular example, Entity A may not have the capability to measure the flow through Bus A; however, the entity may be able to utilize existing measurement points that exist on the four lines that terminate on Bus A to determine the flow as necessary to calculate the hourly integrated gross export from the GCE.



Criterion 2.12 Example 1: Aggregate Weighted Value below 6,000

In example 1 below, BCS are associated with a Control Center that monitors and controls eight BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12 and sum the weighted values for each BES Transmission Line.



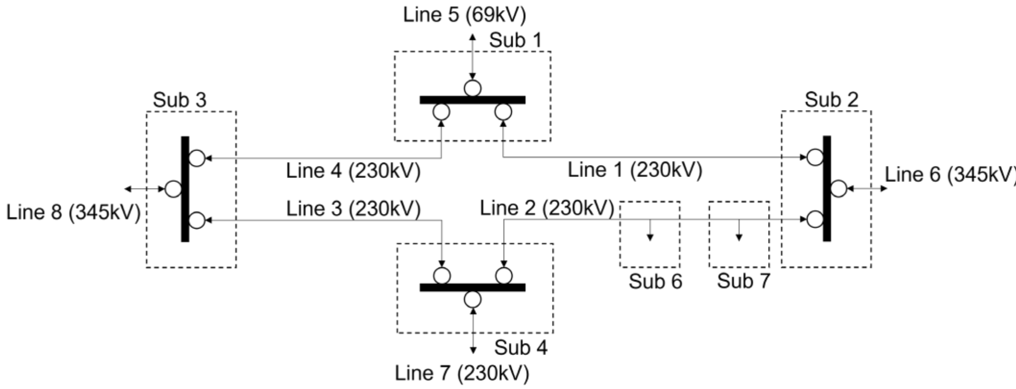
Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 2,000, which is below the minimum threshold for the medium impact rating required in criterion 2.12. The BCS associated with the Control Center in this example should be categorized as low impact BCS pursuant to criterion 3.1.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 1, Line 2, Line 3, Line 4, Line 5, Line 6 Line 7, Line 8	2000
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	None	0
500 kV and above	0	None	0

Criterion 2.12 Example 2: Aggregate Weighted Value exceeds 6,000 with no Exclusion

In example 2 below, BCS are associated with a Control Center that monitors and controls seven BES Transmission Lines. In order to calculate the Control Center's aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12 and sum the weighted values for each BES Transmission Line.



Note: Substation equipment (e.g., transformers) is not shown for simplicity. Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 6,100, which is above the minimum threshold for the medium impact rating required in criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity would be eligible to consider calculating a modified aggregate weighted value that excludes a single GCE in accordance with the exclusion clause; however, in this example, the Responsible Entity either did not choose to pursue an exclusion or did not meet the exclusion criteria. In accordance with criterion 2.12, the BCS associated with the Control Center should be categorized as medium impact BCS.

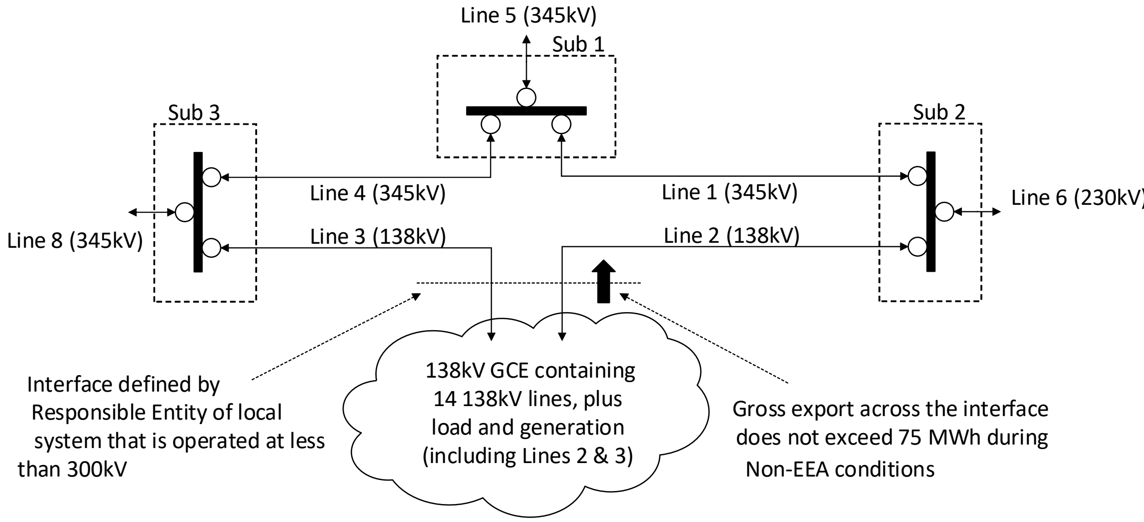
The circles on the diagram indicate the presence of fault-interrupting devices. There are two substations shown (Sub 6 and Sub 7) that are tapped on Line 2 for load serving purposes; however, these substations do not have line fault-interrupting devices that will operate for a fault on Line 2. Therefore, the BES Transmission Line is defined between Sub 2 and Sub 4.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 1, Line 2, Line 3, Line 4, Line 7	3500
300 kV to 499 kV	1300	Line 6, Line 8	2600
500 kV and above	0	None	0

*Line 5 is less than 100 kV; however, no exception has been obtained through the NERC ROP Exception Process and therefore, the line is not BES.

Criterion 2.12 Example 3: Aggregate Weight Value below 6,000 after Applying GCE Exclusion

In example 3 below, BCS are associated with a Control Center that monitors and controls nineteen BES Transmission Lines, of which 14 are to be excluded from the calculation using the GCE exception. The entity should first calculate its aggregate weighted value, referencing the table located in criterion 2.12. The entity is eligible to calculate a modified aggregate weighted value if the original aggregate weighted value is less than 12,000. In order to calculate the Control Center's modified aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12, and the exclusion language, and sum the weighted values for each BES Transmission Line that is not part of a single GCE that was defined by the entity in accordance with the exclusion clause.



Note: Substation equipment (e.g., transformers) is not shown for simplicity.

Circles represent fault interrupting devices.

The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 9,400, which is above the minimum threshold for the medium impact rating required in criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity is eligible to calculate a modified aggregate weighted value that excludes a single GCE in accordance with the exclusion clause.

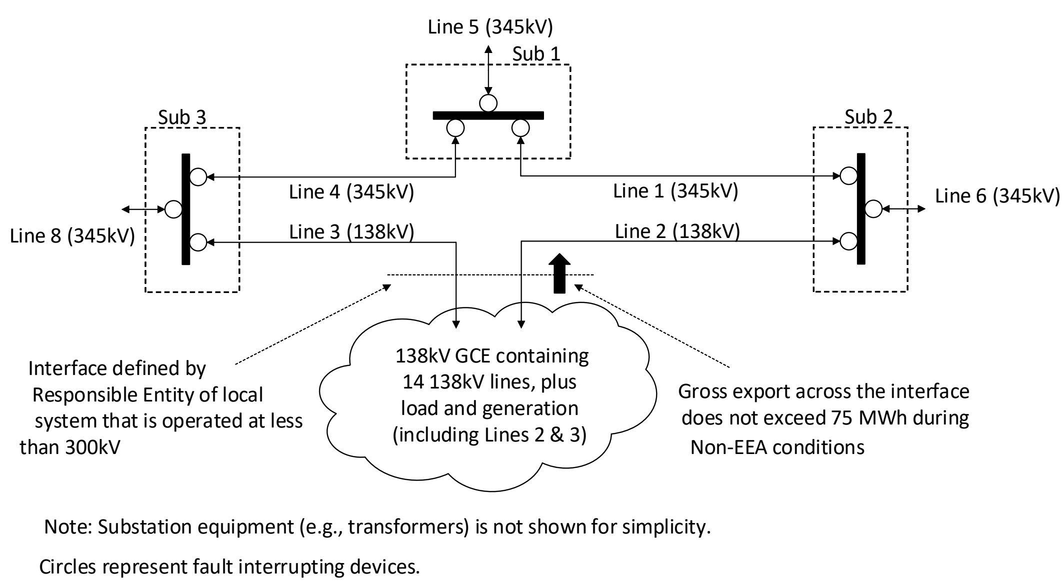
Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 2, Line 3, 12 additional lines	3500
200 kV to 299 kV	700	Line 6	700
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 8	5200
500 kV and above	0	None	0

The calculation of the modified aggregate weighted value is demonstrated below and equates to an aggregate weighted value of 5,900, which is below the minimum threshold for the medium impact rating required in criterion 2.12. The BCS associated with the Control Center in this example should be categorized as low impact BCS pursuant to criterion 3.1.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	Line 6	700
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 8	5200
500 kV and above	0	None	0

*Lines 2 and 3 (along with the 12 additional lines located in the 138 kV GCE) are excluded from the calculation because the Responsible Entity has defined an interface to a GCE that is operated at less than 300kV, where the gross export across the interface does not exceed 75 MWh during non-EEA conditions.

Example 4: Aggregate Weight Value above 6,000 after Applying GCE Exclusion
In example 4 below, BCS are associated with a Control Center that monitors and controls 19 BES Transmission Lines, of which 14 are to be excluded from the calculation using the GCE exception. The entity should first calculate its aggregate weighted value, referencing the table located in criterion 2.12. The entity is eligible to calculate a modified aggregate weighted value if the original aggregate weighted value is less than 12,000. To calculate the Control Center's modified aggregate weighted value, the Responsible Entity should reference the table located in criterion 2.12, and the exclusion language, and sum the weighted values for each BES Transmission Line that is not part of a single GCE that was defined by the entity in accordance with the exclusion clause.



The weighted value for each BES Transmission Line is detailed in the following table by voltage classification. The calculation of the weighted values is demonstrated below and equates to an aggregate weighted value of 10,000, which is above the minimum threshold for the medium impact rating required in criterion 2.12. Given that the calculated aggregated weighted value is less than 12,000, the Responsible Entity is eligible to calculate a modified aggregate weighted value that excludes BES Transmission Lines contained in a single GCE in accordance with the exclusion clause.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	Line 2, Line 3, 12 additional lines	3500
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 6, Line 8	6500
500 kV and above	0	None	0

The calculation of the modified aggregate weighted value is demonstrated below and equates to an aggregate weighted value of 6,500, which is above the minimum threshold for the medium impact rating required in criterion 2.12. In accordance with criterion 2.12, the BCS associated with the Control Center should be categorized as medium impact BCS.

Voltage Value of a BES Transmission Line	Weight Value per BES Transmission Line	Applicable Lines	Weighted Value
< 100 kV	100	None	0
100 kV to 199 kV	250	None	0
200 kV to 299 kV	700	None	0
300 kV to 499 kV	1300	Line 1, Line 4, Line 5, Line 6, Line 8	6500
500 kV and above	0	None	0

*Lines 2 and 3 (along with the 12 additional lines located in the 138kV GCE system) are excluded from the calculation because the Responsible Entity has defined an interface to a GCE that is operated at less than 300kV, where the gross export across the interface does not exceed 75 MWh during non-EEA conditions.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2021-03 CIP-002

Final Ballots Open through November 22, 2024

Now Available

Final ballots are open through **8 p.m. Eastern, Friday, November 22, 2024** for the following standard and implementation plan:

- CIP-002-8 — Cyber Security - BES Cyber System Categorization
- Implementation Plan

Balloting

In the final ballot, votes are counted by exception. Votes from the previous ballot are automatically carried over in the final ballot. Only members of the applicable ballot pools can cast a vote. Ballot pool members who previously voted have the option to change their vote in the final ballot. Ballot pool members who did not cast a vote during the previous ballot can vote in the final ballot.

Members of the ballot pool(s) associated with this project can log into the Standards Balloting and Commenting System (SBS) and submit votes here.

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

Next Steps

The voting results will be posted and announced after the ballots close. If approved, the 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 Standards Developer, Dominique Love (via email) or at (404) 217-7578.

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

BALLOT RESULTS

Ballot Name: 2021-03 CIP-002 CIP-002-Y FN 4 ST
Voting Start Date: 11/13/2024 9:44:42 AM
Voting End Date: 11/22/2024 8:00:00 PM
Ballot Type: ST
Ballot Activity: FN
Ballot Series: 4
Total # Votes: 268
Total Ballot Pool: 297
Quorum: 90.24
Quorum Established Date: 11/13/2024 11:42:59 AM
Weighted Segment Value: 87.12

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	84	1	51	0.773	15	0.227	0	12	6
Segment: 2	7	0.1	1	0.1	0	0	0	5	1
Segment: 3	69	1	48	0.814	11	0.186	0	7	3
Segment: 4	15	1	12	1	0	0	0	2	1
Segment: 5	73	1	47	0.839	9	0.161	0	6	11
Segment: 6	44	1	29	0.879	4	0.121	0	4	7
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	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	5	0.3	3	0.3	0	0	0	2	0
Totals:	297	5.4	191	4.704	39	0.696	0	38	29

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	N/A
1	Ameren - Ameren Services	Tamara Evey		None	N/A
1	American Transmission Company, LLC	Amy Wilke	LaTroy Brumfield	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	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Negative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	BC Hydro and Power Authority	Adrian Andreoiu		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		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	City of College Station	Stacy Engelmann		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	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	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	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	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Negative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Negative	N/A
1	Manitoba Hydro	Nazra Gladu		Negative	N/A
1	MEAG Power	David Weekley	Rebika Yitna	Negative	N/A
1	Muscatine Power and Water	Andrew Kurriger		Affirmative	N/A
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		Negative	N/A
1	National Grid USA	Michael Jones		Negative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Abstain	N/A
1	New York Power Authority	Daniel Valle		Negative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	N/A
1	Northeast Missouri Electric Power Cooperative	Brett Douglas		Negative	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		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		Negative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		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 Pend Oreille County	Angela Hall		None	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

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Salt River Project	Sarah Blankenship	Israel Perez	Affirmative	N/A
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		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		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Abstain	N/A
2	ISO New England, Inc.	John Pearson	John Galloway	Abstain	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Negative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Abstain	N/A
3	Buckeye Power, Inc.	Carl Spaetzel	Ryan Strom	Affirmative	N/A
3	Central Electric Power Cooperative (Missouri)	Adam Weber		Negative	N/A
3	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	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	Great River Energy	Michael Brytowski		Negative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Negative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Negative	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		Negative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Negative	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	Affirmative	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	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	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	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	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Negative	N/A
3	Silicon Valley Power - City of Santa Clara	VAL GUZMAN		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		Affirmative	N/A
3	Tacoma Public Utilities (Tacoma, WA)	John Nierenberg	Jennie Wike	Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Abstain	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	Affirmative	N/A
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		Abstain	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		None	N/A
5	Acciona Energy North America	Truong Le		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith	Brandon Smith	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Negative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Christine Jennings		None	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Bonneville Power Administration	Milli Chennell		Abstain	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	Marie Potter	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	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	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		None	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	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	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	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		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	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	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pacific Gas and Electric Company	Tyler Brun	Michael Johnson	Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	N/A
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		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	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Silicon Valley Power - City of Santa Clara	Sandra Pacheco		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		Affirmative	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	WEC Energy Group, Inc.	Michelle Hribar		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Negative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Cleco Corporation	Robert Hirchak	Clay Walker	Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler	Qinling Zheng	Affirmative	N/A
6	Constellation	Kimberly Turco	Marie Potter	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	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	Great River Energy	Brian Meloy		None	N/A
6	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Negative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	N/A
6	Northern California Power Agency	Dennis Sismaet	Mason Jones	None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		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	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Southern Company - Southern Company Generation and Energy Marketing	Matthew O'neal		Affirmative	N/A
6	Southern Indiana Gas and Electric Co.	Kati Barr		Affirmative	N/A
6	Tacoma Public Utilities (Tacoma, WA)	Terry Gifford	Jennie Wike	Affirmative	N/A
6	Tennessee Valley Authority	Jeffrey Powell		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Abstain	N/A
6	Xcel Energy, Inc.	Steve Szablya		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	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Abstain	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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BALLOT RESULTS

Ballot Name: 2021-03 CIP-002 Implementation Plan FN 4 OT
Voting Start Date: 11/13/2024 9:45:01 AM
Voting End Date: 11/22/2024 8:00:00 PM
Ballot Type: OT
Ballot Activity: FN
Ballot Series: 4
Total # Votes: 261
Total Ballot Pool: 290
Quorum: 90
Quorum Established Date: 11/13/2024 11:43:11 AM
Weighted Segment Value: 91.31

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	82	1	56	0.875	8	0.125	0	12	6
Segment: 2	7	0.1	1	0.1	0	0	0	5	1
Segment: 3	67	1	51	0.895	6	0.105	0	7	3
Segment: 4	15	1	12	1	0	0	0	2	1
Segment: 5	72	1	46	0.852	8	0.148	0	6	12
Segment: 6	43	1	30	0.909	3	0.091	0	4	6
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	Ballot Pool	Segment Weight	Affirmative Votes	Affirmative Fraction	Negative Votes w/ Comment	Negative Fraction w/ Comment	Negative Votes w/o Comment	Abstain	No Vote
Segment: 10	4	0.3	3	0.3	0	0	0	1	0
Totals:	290	5.4	199	4.931	25	0.469	0	37	29

BALLOT POOL MEMBERS

Show All entries Search: Search

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	AEP - AEP Service Corporation	Dennis Sauriol		Affirmative	N/A
1	Allete - Minnesota Power, Inc.	Hillary Creurer		Negative	N/A
1	Ameren - Ameren Services	Tamara Evey		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	Arkansas Electric Cooperative Corporation	Emily Corley		None	N/A
1	Associated Electric Cooperative, Inc.	Mark Riley		Affirmative	N/A
1	Austin Energy	Thomas Standifur		Affirmative	N/A
1	Avista - Avista Corporation	Mike Magruder		Affirmative	N/A
1	Balancing Authority of Northern California	Kevin Smith	Tim Kelley	Affirmative	N/A
1	BC Hydro and Power Authority	Adrian Andreoiu		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Berkshire Hathaway Energy - MidAmerican Energy Co.	Terry Harbour		Affirmative	N/A
1	Black Hills Corporation	Travis Grablander		Affirmative	N/A
1	Bonneville Power Administration	Kamala Rogers-Holliday		Abstain	N/A
1	CenterPoint Energy Houston Electric, LLC	Daniela Hammons		Affirmative	N/A
1	Central Hudson Gas & Electric Corp.	Michael Ridolfino		None	N/A
1	Central Iowa Power Cooperative	Kevin Lyons		Affirmative	N/A
1	City of College Station	Stacy Engelmann		Affirmative	N/A
1	City Utilities of Springfield, Missouri	Michael Bowman		Affirmative	N/A
1	Con Ed - Consolidated Edison Co. of New York	Dermot Smyth		Affirmative	N/A
1	Dairyland Power Cooperative	Karrie Schuldt		Affirmative	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	Georgia Transmission Corporation	Greg Davis	Stephen Stafford	Affirmative	N/A
1	Glencoe Light and Power Commission	Terry Volkmann		Affirmative	N/A
1	Great River Energy	Gordon Pietsch		Negative	N/A
1	Hydro One Networks, Inc.	Emma Halilovic	Ijad Dewan	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Hydro-Quebec (HQ)	Nicolas Turcotte	Chantal Mazza	Affirmative	N/A
1	IDACORP - Idaho Power Company	Sean Steffensen		None	N/A
1	Imperial Irrigation District	Jesus Sammy Alcaraz	Denise Sanchez	Affirmative	N/A
1	International Transmission Company Holdings Corporation	Michael Moltane	Gail Elliott	Affirmative	N/A
1	JEA	Joseph McClung		Abstain	N/A
1	KAMO Electric Cooperative	Micah Breedlove		Affirmative	N/A
1	Lakeland Electric	Larry Watt		None	N/A
1	Lincoln Electric System	Josh Johnson		Affirmative	N/A
1	Long Island Power Authority	Isidoro Behar		Abstain	N/A
1	Los Angeles Department of Water and Power	faranak sarbaz		Affirmative	N/A
1	Lower Colorado River Authority	Matt Lewis	James Baldwin	Abstain	N/A
1	LS Power Transmission, LLC	Jennifer Richardson		Abstain	N/A
1	M and A Electric Power Cooperative	William Price		Affirmative	N/A
1	Manitoba Hydro	Nazra Gladu		Negative	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		Negative	N/A
1	NB Power Corporation	Jeffrey Streifling		Affirmative	N/A
1	Nebraska Public Power District	Jamison Cawley		Affirmative	N/A
1	Network and Security Technologies	Nick Lauriat	Roger Fradenburgh	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	New York Power Authority	Daniel Valle		Negative	N/A
1	NextEra Energy - Florida Power and Light Co.	Silvia Mitchell		Affirmative	N/A
1	NiSource - Northern Indiana Public Service Co.	Alison Nickells		Negative	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		Affirmative	N/A
1	OTP - Otter Tail Power Company	Charles Wicklund		Affirmative	N/A
1	Pacific Gas and Electric Company	Marco Rios	Michael Johnson	Abstain	N/A
1	Pedernales Electric Cooperative, Inc.	Bradley Collard		Abstain	N/A
1	Platte River Power Authority	Marissa Archie		Negative	N/A
1	PNM Resources - Public Service Company of New Mexico	Lynn Goldstein		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 Pend Oreille County	Angela Hall		None	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	Sarah Blankenship	Israel Perez	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
1	Santee Cooper	Chris Wagner		Affirmative	N/A
1	Seminole Electric Cooperative, Inc.	Kristine Ward		Abstain	N/A
1	Sempra - San Diego Gas and Electric	Mohamed Derbas		Affirmative	N/A
1	Southern Company - Southern Company Services, Inc.	Matt Carden		Affirmative	N/A
1	Sunflower Electric Power Corporation	Paul Mehlhaff		Affirmative	N/A
1	Tacoma Public Utilities (Tacoma, WA)	John Merrell	Jennie Wike	Affirmative	N/A
1	Tallahassee Electric (City of Tallahassee, FL)	Scott Langston		Abstain	N/A
1	Tennessee Valley Authority	David Plumb		Negative	N/A
1	Tri-State G and T Association, Inc.	Donna Wood		Affirmative	N/A
1	U.S. Bureau of Reclamation	Richard Jackson		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		Abstain	N/A
2	Electric Reliability Council of Texas, Inc.	Kennedy Meier		Abstain	N/A
2	ISO New England, Inc.	John Pearson	John Galloway	Abstain	N/A
2	Midcontinent ISO, Inc.	Kirsten Rowley		Abstain	N/A
2	New York Independent System Operator	Gregory Campoli		None	N/A
2	PJM Interconnection, L.L.C.	Thomas Foster	Elizabeth Davis	Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
2	Southwest Power Pool, Inc. (RTO)	Joshua Phillips	Shannon Mickens	Affirmative	N/A
3	AEP	Leshel Hutchings		Affirmative	N/A
3	Ameren - Ameren Services	David Jendras Sr		Affirmative	N/A
3	APS - Arizona Public Service Co.	Jessica Lopez		Affirmative	N/A
3	Arkansas Electric Cooperative Corporation	Ayslynn Mcavoy		Abstain	N/A
3	Associated Electric Cooperative, Inc.	Todd Bennett		Affirmative	N/A
3	Austin Energy	Lovita Griffin		Affirmative	N/A
3	Avista - Avista Corporation	Robert Follini		Affirmative	N/A
3	BC Hydro and Power Authority	Ming Jiang		Abstain	N/A
3	Berkshire Hathaway Energy - MidAmerican Energy Co.	Joseph Amato		Affirmative	N/A
3	Black Hills Corporation	Josh Combs		Affirmative	N/A
3	Bonneville Power Administration	Ron Sporseen		Abstain	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	City Utilities of Springfield, Missouri	Jessica Morrissey		Affirmative	N/A
3	CMS Energy - Consumers Energy Company	Karl Blaszkowski		Affirmative	N/A
3	Colorado Springs Utilities	Hillary Dobson		Affirmative	N/A
3	Con Ed - Consolidated Edison Co. of New York	Lincoln Burton		Affirmative	N/A
3	Dominion - Dominion Virginia Power	Victoria Crider		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	DTE Energy - Detroit Edison Company	Marvin Johnson		Abstain	N/A
3	Duke Energy - Florida Power Corporation	Marcelo Pesantez		Affirmative	N/A
3	Edison International - Southern California Edison Company	Romel Aquino		Affirmative	N/A
3	Entergy	James Keele		Affirmative	N/A
3	Evergy	Marcus Moor	Hayden Maples	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	Great River Energy	Michael Brytowski		Negative	N/A
3	Imperial Irrigation District	George Kirschner	Denise Sanchez	Affirmative	N/A
3	KAMO Electric Cooperative	Tony Gott		Affirmative	N/A
3	Lakeland Electric	Steven Marshall		Affirmative	N/A
3	Lincoln Electric System	Sam Christensen		Affirmative	N/A
3	Los Angeles Department of Water and Power	Fausto Serratos		Affirmative	N/A
3	M and A Electric Power Cooperative	Gary Dollins		Affirmative	N/A
3	Manitoba Hydro	Mike Smith		Negative	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		Negative	N/A
3	Nebraska Public Power District	Tony Eddleman		Affirmative	N/A
3	New York Power Authority	Richard Machado		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	NiSource - Northern Indiana Public Service Co.	Steven Taddeucci		Negative	N/A
3	North Carolina Electric Membership Corporation	Chris Dimisa	Scott Brame	Affirmative	N/A
3	Northeast Missouri Electric Power Cooperative	Skyler Wiegmann		Affirmative	N/A
3	Northern California Power Agency	Michael Whitney	Mason Jones	Affirmative	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	OGE Energy - Oklahoma Gas and Electric Co.	Donald Hargrove		Affirmative	N/A
3	Omaha Public Power District	David Heins		Affirmative	N/A
3	OTP - Otter Tail Power Company	Wendi Olson		Affirmative	N/A
3	Owensboro Municipal Utilities	William Berry		Abstain	N/A
3	Pacific Gas and Electric Company	Sandra Ellis	Michael Johnson	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	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	Affirmative	N/A
3	Santee Cooper	Vicky Budreau		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
3	Seminole Electric Cooperative, Inc.	Usama Tahir		None	N/A
3	Sempra - San Diego Gas and Electric	Bryan Bennett		Affirmative	N/A
3	Sho-Me Power Electric Cooperative	Jarrod Murdaugh		Affirmative	N/A
3	Snohomish County PUD No. 1	Holly Chaney		Affirmative	N/A
3	Southern Company - Alabama Power Company	Joel Dembowski		Affirmative	N/A
3	Southern Indiana Gas and Electric Co.	Ryan Snyder		Affirmative	N/A
3	Tennessee Valley Authority	Ian Grant		Negative	N/A
3	Tri-State G and T Association, Inc.	Ryan Walter		Affirmative	N/A
3	WEC Energy Group, Inc.	Christine Kane		Abstain	N/A
3	Xcel Energy, Inc.	Nicholas Friebel		None	N/A
4	Alliant Energy Corporation Services, Inc.	Larry Heckert		Affirmative	N/A
4	Arkansas Electric Cooperative Corporation	Jenni Sudduth		Abstain	N/A
4	Austin Energy	Tony Hua		Affirmative	N/A
4	Buckeye Power, Inc.	Jason Procuniar	Ryan Strom	Affirmative	N/A
4	City Utilities of Springfield, Missouri	Jerry Bradshaw		Affirmative	N/A
4	CMS Energy - Consumers Energy Company	Aric Root		Affirmative	N/A
4	FirstEnergy - FirstEnergy Corporation	Mark Garza		Affirmative	N/A
4	North Carolina Electric Membership Corporation	Richard McCall	Scott Brame	Affirmative	N/A
4	Northern California Power Agency	Marty Hostler	Mason Jones	Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
4	Public Utility District No. 1 of Snohomish County	John D. Martinsen		Affirmative	N/A
4	Sacramento Municipal Utility District	Foung Mua	Tim Kelley	Affirmative	N/A
4	Seminole Electric Cooperative, Inc.	George Pino		Abstain	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		None	N/A
5	Acciona Energy North America	Truong Le		None	N/A
5	AEP	Thomas Foltz		Affirmative	N/A
5	AES - AES Corporation	Ruchi Shah		Affirmative	N/A
5	Ameren - Ameren Missouri	Sam Dwyer		Affirmative	N/A
5	American Municipal Power	Amy Ritts		Affirmative	N/A
5	APS - Arizona Public Service Co.	Andrew Smith	Brandon Smith	Affirmative	N/A
5	Associated Electric Cooperative, Inc.	Chuck Booth		Affirmative	N/A
5	Austin Energy	Michael Dillard		Affirmative	N/A
5	Avista - Avista Corporation	Glen Farmer		Affirmative	N/A
5	BC Hydro and Power Authority	Christine Jennings		None	N/A
5	Berkshire Hathaway - NV Energy	Dwanique Spiller		Affirmative	N/A
5	Black Hills Corporation	Sheila Suurmeier		Affirmative	N/A
5	Bonneville Power Administration	Milli Chennell		Abstain	N/A
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	Marie Potter	Affirmative	N/A
5	Cowlitz County PUD	Deanna Carlson		Affirmative	N/A
5	Dairyland Power Cooperative	Tommy Drea		Affirmative	N/A
5	Decatur Energy Center LLC	Megan Melham		Affirmative	N/A
5	Duke Energy	Dale Goodwine		Affirmative	N/A
5	Edison International - Southern California Edison Company	Selene Willis		None	N/A
5	EDP Renewables North America LLC	Heather Morgan		None	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	Florida Municipal Power Agency	Chris Gowder	LaKenya Vannorman	None	N/A
5	Great River Energy	Jacalynn Bentz		Negative	N/A
5	Greybeard Compliance Services, LLC	Mike Gabriel		Affirmative	N/A
5	Imperial Irrigation District	Tino Zaragoza	Denise Sanchez	Affirmative	N/A
5	JEA	John Babik		None	N/A
5	Lakeland Electric	Carmen Rodriguez		None	N/A
5	Lincoln Electric System	Brittany Millard		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Los Angeles Department of Water and Power	Robert Kerrigan		Affirmative	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	N/A
5	Muscatine Power and Water	Chance Back		Affirmative	N/A
5	National Grid USA	Robin Berry		Negative	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		Negative	N/A
5	NiSource - Northern Indiana Public Service Co.	Kathryn Tackett		Negative	N/A
5	North Carolina Electric Membership Corporation	Reid Cashion	Scott Brame	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	Oglethorpe Power Corporation	Donna Johnson		Affirmative	N/A
5	Omaha Public Power District	Kayleigh Wilkerson		Affirmative	N/A
5	Ontario Power Generation Inc.	Constantin Chitescu		Negative	N/A
5	OTP - Otter Tail Power Company	Stacy Wahlund		Affirmative	N/A
5	Pacific Gas and Electric Company	Tyler Brun	Michael Johnson	Abstain	N/A
5	Pattern Operators LP	George E Brown		Negative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
5	Pine Gate Renewables	Michiko Sell		None	N/A
5	Platte River Power Authority	Jon Osell		Affirmative	N/A
5	Portland General Electric Co.	Ryan Olson		Abstain	N/A
5	PPL - Louisville Gas and Electric Co.	Julie Hostrander		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	Sacramento Municipal Utility District	Ryder Couch	Tim Kelley	Affirmative	N/A
5	Salt River Project	Thomas Johnson	Israel Perez	Affirmative	N/A
5	Santee Cooper	Carey Salisbury		Affirmative	N/A
5	Seminole Electric Cooperative, Inc.	Melanie Wong		Abstain	N/A
5	Sempra - San Diego Gas and Electric	Jennifer Wright		Affirmative	N/A
5	Southern Company - Southern Company Generation	Leslie Burke		Affirmative	N/A
5	Southern Indiana Gas and Electric Co.	Larry Rogers		Affirmative	N/A
5	Talen Generation, LLC	Donald Lock		None	N/A
5	Tennessee Valley Authority	Darren Boehm		Negative	N/A
5	Tri-State G and T Association, Inc.	Sergio Banuelos		Affirmative	N/A
5	U.S. Bureau of Reclamation	Wendy Kalidass		Affirmative	N/A
5	WEC Energy Group, Inc.	Michelle Hribar		Abstain	N/A
5	Xcel Energy, Inc.	Gerry Huitt		Affirmative	N/A
6	Ameren - Ameren Services	Robert Quinlivan		Affirmative	N/A
6	APS - Arizona Public Service Co.	Marcus Bortman		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Arkansas Electric Cooperative Corporation	Bruce Walkup		Abstain	N/A
6	Associated Electric Cooperative, Inc.	Brian Ackermann		Affirmative	N/A
6	Austin Energy	Imane Mrini		Affirmative	N/A
6	Berkshire Hathaway - PacifiCorp	Lindsay Wickizer		None	N/A
6	Black Hills Corporation	Rachel Schuldt		Affirmative	N/A
6	Bonneville Power Administration	Tanner Brier		Abstain	N/A
6	Cleco Corporation	Robert Hirchak	Clay Walker	Affirmative	N/A
6	Con Ed - Consolidated Edison Co. of New York	Jason Chandler	Qinling Zheng	Affirmative	N/A
6	Constellation	Kimberly Turco	Marie Potter	Affirmative	N/A
6	Dominion - Dominion Resources, Inc.	Sean Bodkin		Affirmative	N/A
6	Duke Energy	John Sturgeon		Affirmative	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	Lakeland Electric	Paul Shipps		None	N/A
6	Lincoln Electric System	Eric Ruskamp		Affirmative	N/A
6	Los Angeles Department of Water and Power	Anton Vu		Affirmative	N/A
6	Manitoba Hydro	Brandin Stoesz	David Wells	Negative	N/A
6	Muscatine Power and Water	Nicholas Burns		Affirmative	N/A
6	New York Power Authority	Shelly Dineen		Negative	N/A
6	NextEra Energy - Florida Power and Light Co.	Justin Welty		Affirmative	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	NiSource - Northern Indiana Public Service Co.	Rebecca Blair		Negative	N/A
6	Northern California Power Agency	Dennis Sismaet	Mason Jones	None	N/A
6	NRG - NRG Energy, Inc.	Martin Sidor		Affirmative	N/A
6	OGE Energy - Oklahoma Gas and Electric Co.	Ashley F Stringer		Affirmative	N/A
6	Omaha Public Power District	Shonda McCain		Affirmative	N/A
6	Platte River Power Authority	Sabrina Martz		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	Affirmative	N/A
6	Santee Cooper	Marty Watson		Affirmative	N/A
6	Seminole Electric Cooperative, Inc.	Bret Galbraith		None	N/A
6	Snohomish County PUD No. 1	John Liang		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		None	N/A
6	WEC Energy Group, Inc.	David Boeshaar		Abstain	N/A

Segment	Organization	Voter	Designated Proxy	Ballot	NERC Memo
6	Xcel Energy, Inc.	Steve Szablya		Affirmative	N/A
10	Northeast Power Coordinating Council	Gerry Dunbar		Abstain	N/A
10	SERC Reliability Corporation	Dave Krueger		Affirmative	N/A
10	Texas Reliability Entity, Inc.	Rachel Coyne		Affirmative	N/A
10	Western Electricity Coordinating Council	Steven Rueckert		Affirmative	N/A

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NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Exhibit F

Standard Drafting Team Roster, Project 2021-03 CIP-002

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Drafting Team Roster

Project 2021-03 CIP-002

	Name	Entity
Chair	Megan Sauter	Oncor Electric Delivery
Vice Chair	Russell Noble	American Public Power Association (APPA)
Members	Josh Aldridge	Ferrovial
	Mark Atkins	Acumen
	Brian Evans-Mongeon	Village of Hyde Park
	Barry Jones	Western Area Power Administration (WAPA)
	Josh Powers	Southwest Power Pool (SPP)
	Jennifer Tidwell	Southern Company
	Dawn Triplett	American Electric Power (AEP)
	Terry Volkmann	Volkmann Consulting
PMOS	Darrel Grumman	EPE Consulting
	Ellese Murphy	Duke-Energy
NERC Staff	Dominique Love, Standards Developer	North American Electric Reliability Corporation
	Sarah Crawford, Counsel	North American Electric Reliability Corporation
	Marisa Hecht, Counsel	North American Electric Reliability Corporation
	Davis Jelusich, Compliance	North American Electric Reliability Corporation