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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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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The SDT analyzed 22 responses, from 20 active and 2 withdrawn participants who provided relevant information prior to withdrawal.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

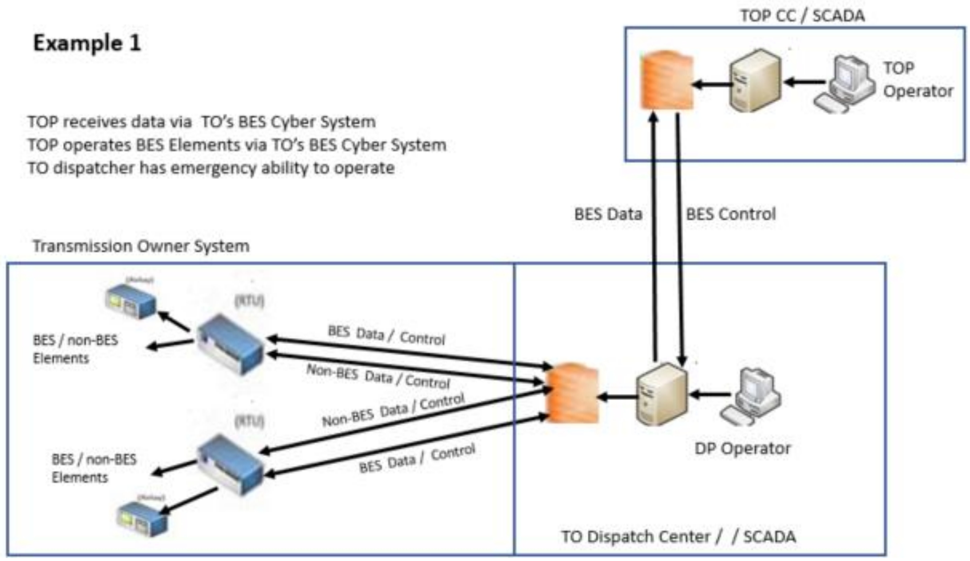
In addition, the SDT observed a lack of clarity regarding the application of the Control Center definition to locations where cyber assets are not associated with control of BES Elements but rather are used to aggregate data for the TOP at unmanned sites. This is in contrast to the original inclusion 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.

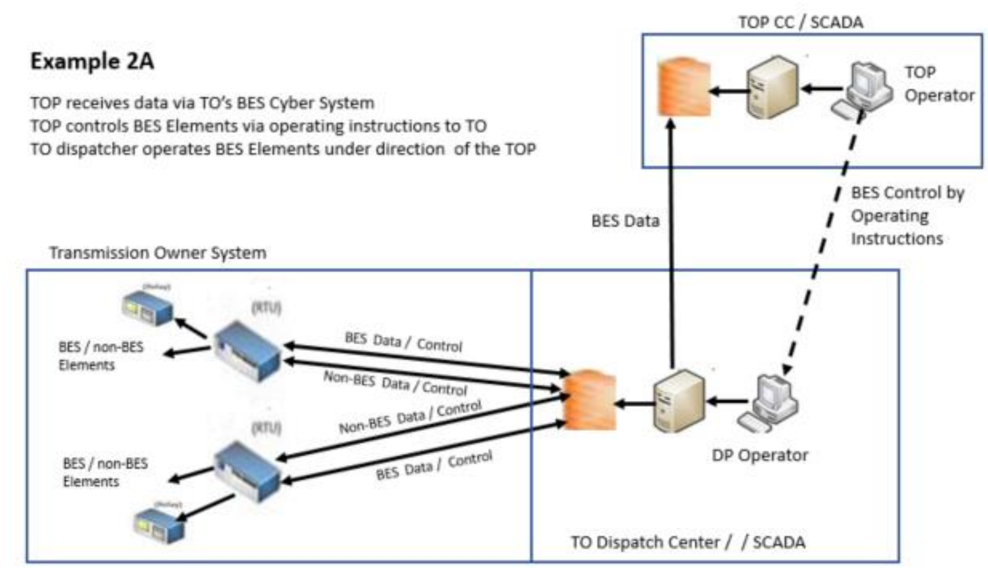
Appendix A: TO/TOP Configurations

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.

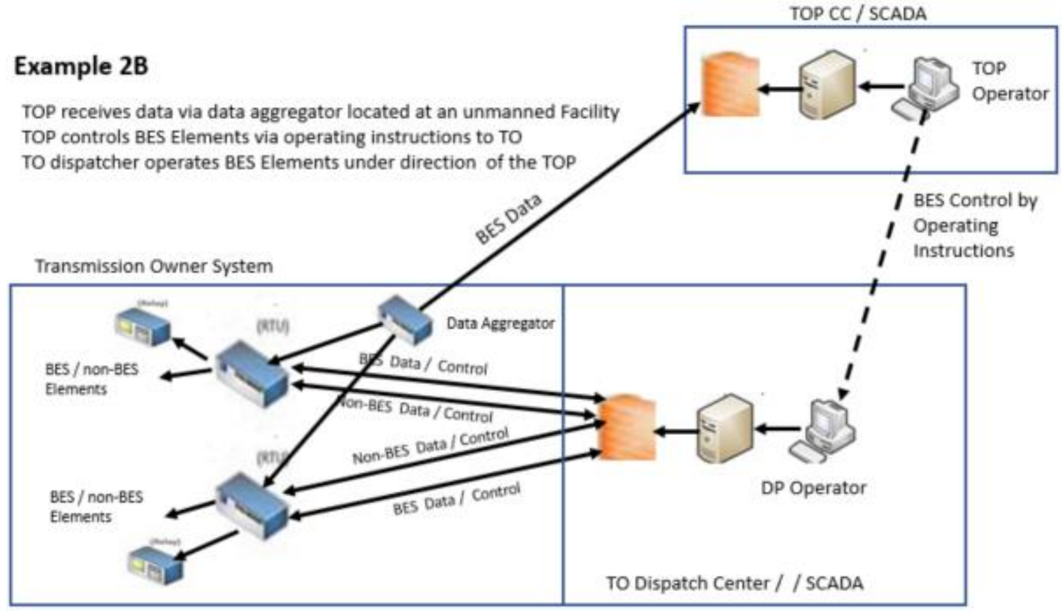
Example 1: TO BES Cyber System should be considered a data center used by the TO to monitor and control BES Elements in real-time to perform the reliability tasks of the TOP. In this model, the TO Dispatch Center should be considered a TO Control Center due to having the capability to control BES Elements.



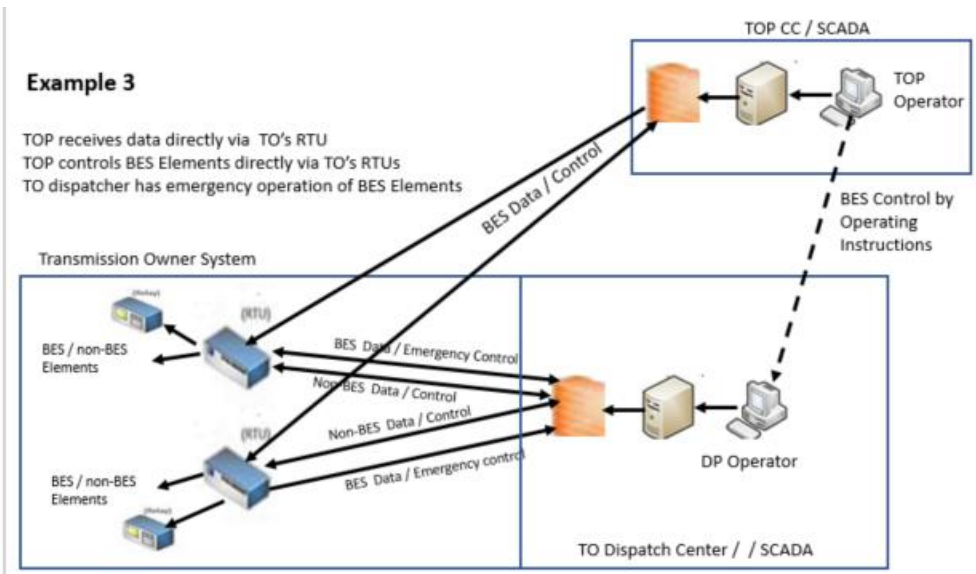
Example 2A: TO BES Cyber System should be considered a data center used by the TO to monitor and control BES Elements in real-time to perform the reliability tasks of the TOP. In this model, the TO Dispatch Center should be considered a TO Control Center due to having the capability to control BES Elements.



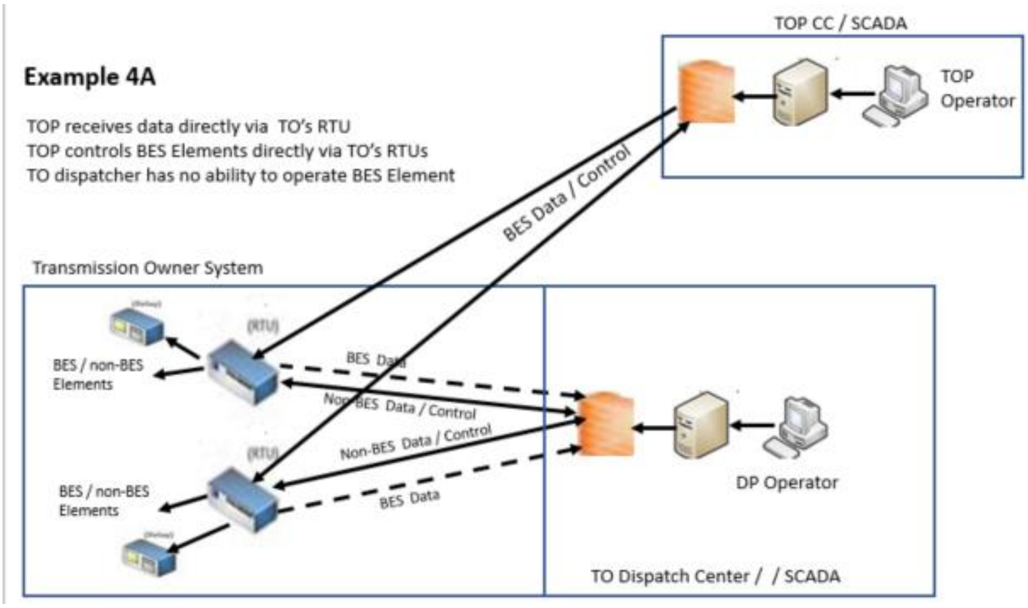
Example 2B: TO BES Cyber System should be considered a data center used by the TO to monitor and control BES Elements in real-time to perform the reliability tasks of the TOP. In this model, the TO Dispatch Center should be considered a TO Control Center due to having the capability to control BES Elements.



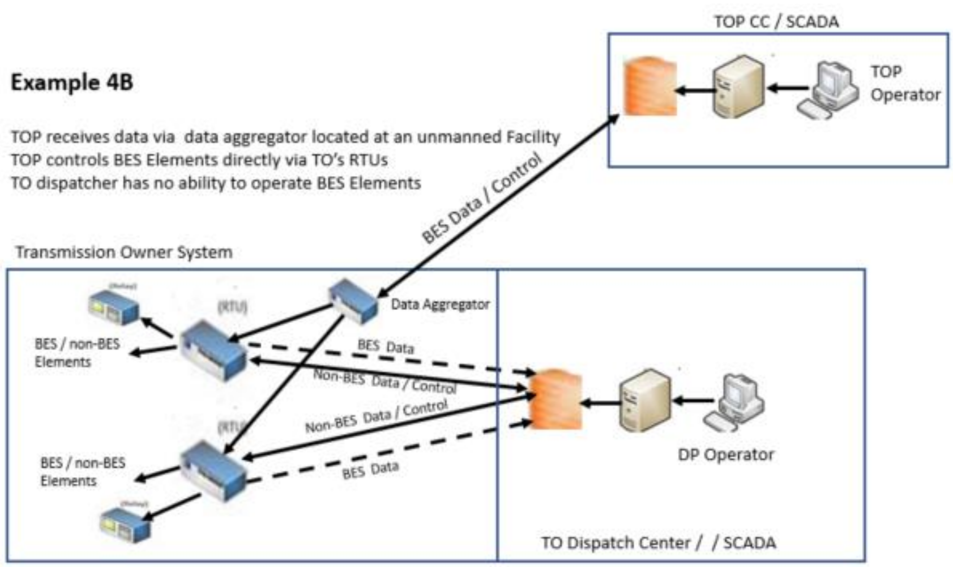
Example 3: TO BES Cyber System should be considered a data center used by the TO to monitor and control BES Elements in real-time to perform the reliability tasks of the TOP in an emergency. In this model, the TO Dispatch Center should be considered a TO Control Center due to having the capability to 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?

   ____

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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

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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

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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			

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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

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				

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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		

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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.

____

____

____

____

____