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: