Comment Report

Project Name:	2021-03 CIP-002 | Draft 1
Comment Period Start Date:	9/26/2023
Comment Period End Date:	11/9/2023
Associated Ballots:	2021-03 CIP-002 CIP-002-Y IN 1 ST 2021-03 CIP-002 Implementation Plan IN 1 OT

There were 78 sets of responses, including comments from approximately 172 different people from approximately 111 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The SDT has modified the Control Center definition based on ambiguity that surfaced during the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

2. The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". This was intentional, to make clear that the BES Cyber Systems to consider differ between Control Centers and other assets such as Transmission stations and Generation resources. In alignment with Part 1 of Attachment 1, BES Cyber Systems 'used by and located at' Control Centers need to be considered. This prevents expanding from Control Centers down into field assets. With respect to other assets, it is BES Cyber Systems 'associated with' the assets that are considered. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

3. The SDT revised CIP-002-Y Attachment 1 Criterion 2.12 based on data obtained from the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

4. Provide any additional comments for the SDT to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
BC Hydro and Power Authority	Adrian Andreoiu	1	WECC	BC Hydro	Hootan Jarollahi	BC Hydro and Power Authority	3	WECC
					Helen Hamilton Harding	BC Hydro and Power Authority	5	WECC
					Adrian Andreoiu	BC Hydro and Power Authority	1	WECC
MRO	Anna Martinson	1,2,3,4,5,6	MRO	MRO Group	Shonda McCain	Omaha Public Power District (OPPD)	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Jay Sethi	Manitoba Hydro (MH)	1,3,5,6	MRO
					Jaimin Patal	Saskatchewan Power Corporation (SPC)	1	MRO
					Kimberly Bentley	Western Area Power Adminstration	1,6	MRO
					Marc Gomez	Southwestern Power Administration (SWPA)	1	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO
					George Brown	Pattern Operators LP	5	MRO
					Larry Heckert	Alliant Energy (ALTE)	4	MRO
					Terry Harbour	MidAmerican Energy Company (MEC)	1,3	MRO
					Bryan Sherrow	Board Of	1	MRO

						Public Utilities (BPU)		
					Seth Shoemaker	Muscatine Power & Water	1,3,5,6	MRO
					Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Michael Ayotte	ITC Holdings	1	MRO
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	TVA RBB	Ian Grant	Tennessee Valley Authority	3	SERC
					David Plumb	Tennessee Valley Authority	1	SERC
					Armando Rodriguez	Tennessee Valley Authority	6	SERC
					Nehtisha Rollis	Tennessee Valley Authority	5	SERC
WEC Energy Group, Inc.	Christine Kane	3		WEC Energy Group	Christine Kane	WEC Energy Group	3	RF
					Matthew Beilfuss	WEC Energy Group, Inc.	4	RF
					Clarice Zellmer	WEC Energy Group, Inc.	5	RF
					David Boeshaar	WEC Energy Group, Inc.	6	RF
Austin Energy	Imane Mrini	6		Austin Energy	Imane Mrini	Austin Energy	6	Texas RE
					Michael Dillard	Austin Energy	5	Texas RE
					Lovita Griffin	Austin Energy	3	Texas RE
					Tony Hua	Austin Energy	4	Texas RE
					Thomas Standifur	Austin Energy	1	Texas RE
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma	4	WECC

						Public Utilities (Tacoma, WA)		
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Ryan Strom	Buckeye Power, Inc	4	RF
					Jim Davis	East Kentucky Power Cooperative	1,3	SERC
					Scott Brame	North Carolina Electric Membership Corporation	3,4,5	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF

California ISO	Monika Montez	2	WECC	ISO/RTO Council Standards Review Committee (SRC)	Monika Montez	CAISO	2	WECC
					Bobbi Welch	Midcontinent ISO, Inc.	2	RF
					Kathleen Goodman	ISO-NE	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Helen Lainis	IESO	2	NPCC
					Charles Yeung	Southwest Power Pool, Inc. (RTO)	2	MRO
					Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
					Leslie Burke	Southern Company - Southern Company Generation	5	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC

					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Glen Smith	Entergy	4	NPCC

						Services		
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC
					ALAN ADAMSON	New York State Reliability Council	10	NPCC
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
Ryan Strom	Ryan Strom		RF	Buckeye Power Group	Carl Spaetzel	Buckeye Power, Inc.	3	RF
					Jason Procuniar	Buckeye Power, Inc.	4	RF
					Kevin Zemanek	Buckeye Power, Inc.	5	RF
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
Western Electricity	Steven Rueckert	10		WECC CIP	Steve Rueckert	WECC	10	WECC
					Morgan King	WECC	10	WECC

Coordinating Council					Deb McEndaffer	WECC	10	WECC
					Tom Williams	WECC	10	WECC

1. The SDT has modified the Control Center definition based on ambiguity that surfaced during the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1

Answer	No
Document Name	

Comment

The description is wordy, is a run-on sentence, and preserves the existing ambiguity regarding what "monitor and control" is in the context of real-time. Our TO organization has an agreement with a third party to "monitor" our limited assets. Many small TO utilities do not "monitor and control in real-time". Monitoring is passive and after-the-fact, not real-time. TO's do not "operate", according to NERC functional definitions, and thus cannot have "operating personnel". We recognize there are larger TO's who have massive Control Centers, and by definition they do "monitor and operate" and should be registered as TOPs. Furthermore, smaller entities like us may have the ability to select a device and open it or close it, but it is only if we are directed to act by our TOP or RC through our agreements. This is not real-time because we do not monitor the overall BES and are not aware of the overall impacts of the operation. Any operation we do is clearly limited, and it is approved ahead-of-time for maintenance and testing purposes, unless otherwise directed. This, in our interpretation, is not real-time operation. Our staff's focus is monitoring and operating a distribution system, the inclusion of our facilities in the definition of a "Control Center" over states what our staff does, and it leads us to believe that NERC System Operator Certification may be required for anyone who may electronically switch their 100kV assets for working on their own distribution system.

A second concern is that smaller generators may use two separate and distinct systems to manage two separate generation facilities from a common room. Furthermore, generation Facilities may be geographically separated, or in the same local area. Bullet #5 doesn't distinguish between NERC registered generation and other small generation. We feel the inclusion of a 980Kw generator in a larger 88Mw facility could be interpreted to be two generation Facilities operated from the same location, thereby making this a Control Center under the new definition.

Overall, it is our feeling that bullets 4 and 5 should not be included, and that this definition should focus on BAs, RCs, and TOPs. The lead in language should be amended to state:

"Control Center - One or more facilities where an RC, BA or TOP hosts NERC Certified operating personnel to monitor and control the Bulk Electric System (BES) in real-time, as described below, including location of the associated Cyber Assets used by to monitor and control the BES in real-time. "

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

Initially, we felt the SAR only allowed for modification to the definition of Control Center as it relates to TO's only. After meeting and talking with the SDT, during their recent webinar, we feel that changing the definition of Control Center for TOs, RCs, BAs, and GOPs, collectively, is allowed, and is appropriate. However, it would not be acceptable to us if the SDT proposed changing the definition for TOs, RCs, and/or BAs, collectively, but excluded

GOPs.	
Likes 0	
Dislikes 0	
Response	
Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	No
Document Name	
Comment	

The standard drafting team has done an excellent job in clarifying a complex definition. The use of one definition for both the control room and associated data center is effective and clear.

There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center, however the generators are individual Facilities and are located over a large physical area.

The following definition is proposed:

4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or

5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	No
Document Name	
Comment	

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5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group

Answer	No
Document Name	

Comment

Buckeye supports the comments made by ACES:

ACES suggests changing “Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units” to “Field assets, such as remote terminal units, are excluded from the scope of the Control Center’s definition” to avoid ambiguity.

Likes 0	
Dislikes 0	

Response

Paul Mehlhaff - Sunflower Electric Power Corporation - 1

Answer	No
Document Name	

Comment

Sunflower does not believe a modification to the Control Center definition is required.

Likes 0	

Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

Tacoma Power appreciates the revisions made by the SDT based on the previous informal comment period. Tacoma Power agrees with many of the changes made to the Control Center definition. However, the Control Center definition is still ambiguous on exactly what Cyber Assets are intended to be included. For example, is the intent to include control panels used by operating personnel, the energy management system or the entire system including servers and communication gear?

Tacoma Power recommends additional changes to provide clarity, as follows. Instead of referring to Cyber Assets, the definition should refer to BES Cyber Systems, as this would capture the associated data centers. This change would leverage existing NERC Glossary of Terms to reduce the ambiguity.

Proposed change: "including any spaces that house the **BES** Cyber **System** used by operating personnel to monitor and control the BES in real-time."

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5

Answer	No
Document Name	

Comment

"See comments submitted by the Edison Electric Institute"

Comments: While EEI supports the inclusion of BES into the purpose statement, we do not support replacing the defined term "Facility" with the undefined term "resource". This change does not add any improved clarity and the term Facility should be restored in the Purpose statement.

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI’s proposed alternative of not changing the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	

Comment	
The use of one definition for both the control room and associated data center is effective and clear. There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center, however the generators are individual Facilities and are located over a large physical area. The following definition is proposed: 4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or 5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	No
Document Name	
Comment	
From the Technical Rationale "The phrase “any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time” was developed to replace “associated data center”. Do the spaces located in a room that does not house operating personnel, but is in the same building as a room that houses operating personnel (shared street address) and the spaces located in a separate building from any rooms that house operating personnel get classified as Control Centers? These spaces were known as “associated data centers” and were not included in the count of Control Centers. Clarifying language is needed in the definition that states if the rooms, that do not physically host operating personnel, are not classified as Control Centers. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No

Document Name	

Comment
The proposed changes are too specific to the architecture of the building and does not provide clarity on what is meant by “hosting”. For example: A small municipal utility has the capability to monitor and control the two Transmission substations that they own through their SCADA system: {C}1) If there is a desk with a SCADA HMI located in the engineering office that may be used by any of the utility engineers but no one is assigned to that desk, is the engineering office a Control Center? or {C}2) If the configuration listed above is a Control Center, can the Control Center classification be removed if the SCADA desk is moved into the hallway or the parking lot? or {C}3) If the engineers can remote into the SCADA from their computers at their desk, is the engineering office a Control Center? or {C}4) If an engineer remotes into the SCADA system from a remote (room) location (home office, Starbucks) is this room now a Control Center? {C}5) If the utility has a room that houses equipment for SCADA access but is only staffed during poor weather events for the purpose of dispatching field personnel, is this room a Control Center?

Likes 0	
Dislikes 0	

Response

Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	

Comment
AEPC signed on to ACES comments below: ACES suggests changing “Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units” to “Field assets, such as remote terminal units, are excluded from the scope of the Control Center’s definition” to avoid ambiguity.

Likes 0	
Dislikes 0	

Response

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	No
Document Name	
Comment	
LCRA believes the changing of the definition of Control Center is outside of the scope of the SAR and has unintended consequences to other standards.	
Likes 0	
Dislikes 0	
Response	

David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports NAGF's comments on this project	
Likes 0	
Dislikes 0	
Response	

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	No
Document Name	
Comment	
ACES suggests changing “Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units” to “Field assets, such as remote terminal units, are excluded from the scope of the Control Center’s definition” to avoid ambiguity.	
Likes 0	
Dislikes 0	
Response	

Teresa Krabe - Lower Colorado River Authority - 5	
Answer	No
Document Name	
Comment	
LCRA believes the changing of the definition of Control Center is outside of the scope of the SAR and has unintended consequences to other standards.	
Likes 0	
Dislikes 0	
Response	

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	
PNMR (TNMP and PNM) agrees with EEI Comments. Specifically, we support the alternative recommendation to create a new defined term for TOCC. PNMR agrees with leaving the existing definition of Control Center since it is in several other CIP and O&P requirements. We believe changing the definition would require a SAR to change the definition or modify the standards that use the definition. Instead, the SDT should create a new definition Transmission Owner Control Center that is only used in CIP-002 as the NERC Rules of Operating Procedure doesn't recognize Transmission Owners having responsibilities associated with a control center. This avoids adversely affecting a definition a majority do not have a problem with and allow the SDT to scope in Transmission Owner Control Centers in CIP-002 which is the only place it comes up because of a FERC order	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	No
Document Name	
Comment	
While WECC recognizes the need for the SDT to provide clarity to this complex definition, some of the modifications to the Control Center definition appear to have also created unintended consequences as well. In the context of Associated Data Center - "A space that houses Cyber Assets used by operating personnel to monitor and control the BES in real-time may be: • located in the same room that houses operating personnel."	

This proposed revision appears to bring a home office where personnel using a Cyber Asset with Interact Remote Access (IRA) to monitor and control the BES in real-time into scope as a Control Center. In the context of IRA, the standards have not brought in the remote Cyber Asset into scope as any applicable system of the standards, but the first bullet appears to bring a home office into scope as a Control Center and Cyber Asset with this capability into scope as a BCA.

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	

BC Hydro appreciates drafting team's efforts and the opportunity to comment, and provides the following.

Proposed modifications to the definition of Control Centre don't align with CIP-002.5.1a Attachment 1 high and medium impact Control Center criteria 1.1 to 1.4 and 2.11 to 2.13 as these Control Centre criteria still use "perform functional obligations" language which is equivalent to "to perform the reliability tasks" SDT tried to replace. For instance, in a GOP control room, the operating personnel are capable of controlling generating units at two generation plants, but they don't perform GOP obligations that are only taken by the GOP System Operators. Even though this GOP control room would become a Control Centre based on the modified Control Centre definition, it wouldn't meet any high or medium Control Center impact rating criteria thus only becoming a low impact Control Center.

The language around "the capability to electronically control Transmission Facilities at two or more locations has a Control Center" is vague and could encompass facilities and locations that definitely should not be considered control centers.

The SDT is requested to consider not removing 'reliability-related tasks' from the currently defined terms as this will further clarify who is 'operating personnel'.

BCH also seeks clarity on the use of the word 'capability'. SDT should allow for provisions where protections have been implemented that reduce/impair 'capability', but there still exists the possibility without those protections.

The inclusion of points 4 and 5 (in Control Center Definition) for consideration of operating personnel (i.e. technicians and electricians may qualify) would effectively turn any generation control room that has the capability to electronically control a local and remote BES asset into a Control Center.

BC Hydro suggest that SDT provide some use cases and examples to clarify this, and makes the following recommendations:

1) Modify CIP-002 Attachment 1 criteria 1.1 to 1.4 and 2.11 to 2.13 to change "perform functional obligations" to "control Facilities".

2) Provide clarity of the use term 'operating personnel' in item 4 and 5 of Control Center definition and use of the term 'capability' with use cases and examples.

3) In the Control Center definition suggest changing the points 1 or 2 or 3 or 4 or 5 to: 1 or 2 or 3 or (1 or 2 or 3 and 4) or (1 or 2 or 3 and 5). This will ensure that Real-time monitoring and control of the BES is occurring, instead of including in the Control Center definition control rooms only performing local load control.

Likes 0	

Dislikes 0	
Response	
Thomas Standifur - Austin Energy - 1	
Answer	No
Document Name	
Comment	
Austin Energy believes the proposed change to the definition of Control Center is too broad and vague with the inclusion of “any spaces that house”. In addition, a change to this core definition could have cascading impacts to other NERC standards and introduce potential conflict and confusion. In addition, the SAR does not include/request a definition change.	
Likes 1	Austin Energy, 6, Mrini Imane
Dislikes 0	
Response	
Imane Mrini - Austin Energy - 6, Group Name Austin Energy	
Answer	No
Document Name	
Comment	
The proposed change to the definition of Control Center is too broad and vague with the inclusion of “any spaces that house”. In addition, a change to this core definition could have cascading impacts to other NERC standards and introduce potential conflict and confusion. In addition, the SAR does not include/request a definition change.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments and recommends the changes proposed for the definition by EEI.	
Likes 0	

Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

FirstEnergy supports EEI's comments which state:

EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface):

Control Center - One or more **facilities** where a responsible entity **houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **Cyber Assets BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **located** in a centralized location and exclude field assets such as remote terminal units.

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations;

4. Transmission Owner **facilities who that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or

5. Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for** generation Facilities at two or more **separate physical** locations.

Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition.

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments and EEI's proposed alternative of not changing the Control Center definition	
Likes 0	
Dislikes 0	
Response	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Eversource supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	No
Document Name	
Comment	
From the Technical Rationale "The phrase “any spaces that house the Cyber Assets used by operating personnel to monitor and control the BES in real-time” was developed to replace “associated data center”. Do the spaces located in a room that does not house operating personnel, but is in the same building as a room that houses operating personnel (shared street address) and the spaces located in a separate building from any rooms that house operating personnel get classified as Control Centers? These spaces were known as “associated data centers” and were not included in the count of Control Centers. Clarifying language is needed in the definition that states if the rooms, that do not physically host operating personnel, are not classified as Control Centers. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	No
Document Name	
Comment	

AEP supports the comments made by EEI. Specifically:

EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface):

Control Center - One or more **facilities** where a responsible entity **houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **located** in a centralized location and exclude field assets such as remote terminal units.

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations;

4. Transmission Owner **facilities who that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or

5. Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for** generation Facilities at two or more **separate physical** locations Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition. Kent Feliks on behalf of AEP in Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon is responding in support of EEI's response to this question.	
Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE supports EEI's comments: "EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface): **Control Center** - One or more **facilities rooms** where a responsible entity **hosts houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **any spaces that house the Cyber Assets BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **Cyber Assets BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **housed located** in a centralized location and exclude field assets such as remote terminal units.	

Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations;

. **Operating personnel of a** Transmission Owner **facilities who that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or

Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for who have the capability to electronically control** generation Facilities at two or more **separate physical** locations; **in real-time**.

Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Southern Company agrees with the comments from EEI.

Likes 0	
Dislikes 0	

Response

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group

Answer	No
Document Name	

Comment

WEC Energy Group supports the comments of the MRO NSRF.

Additionally, we support the following comment proffered by EEI:

"Alternatively, the SDT could consider not modifying the Control Center definition and creating a separate definition solely for use in CIP-002, which would target TO Control Centers. Given these Facilities are really Operations Centers (i.e., used at the direction of the TOP), a separate definition could be developed that more directly addresses the concerns expressed in the SAR without materially modifying the existing Control Center definition."	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS does not agree with the proposed changes but does supports the comments that were submitted by EEI on behalf of their members to improve the definition for Control Centers. Either by incorporating their proposed submitted changes or by their submitted suggestion of creating a CIP-002 specific definition for Control Centers targeting TO Control Centers.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	

Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	
Response	

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Insititute (EEI) for question #1.	
Likes 0	
Dislikes 0	
Response	

Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	No
Document Name	
Comment	
Suggest to change to “One or more designated rooms or buildings…” in order to avoid calling any area including remote locations where operating personnel may monitor and/or control remotely with their approved cyber assets, such as engineering workstation. Suggest to define operating personnel so that the role is only active inside Control Center (i.e. remote monitoring and controlling outside of Control Center not allowed)	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	

Comment	
The NAGF notes that the field test did not include REs from the other functional models impacted by the proposed changes. Therefore, the NAGF recommends preserving the current Control Center definition language and incorporating additional language to directly address the Transmission Owner risk(s). This approach will avoid unintended consequences such as the potential expansion of in scope Cyber Assets applicable under the revised language addressing data centers.	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI supports efforts to improve the definition for Control Center, but additional modification are still needed to prevent unintended impacts given the term's extensive use in other CIP and O&P Reliability Standards. Among our concerns with the proposed definition include the changes to the language for GOPs, which appears to expand the scope for those entities inappropriately. While this effort was intended to address TO control centers issues, the proposed changes appear to have unintentionally, through the removal of "perform reliability related tasks" from the overall definition, changed the scope for GOPs to include any generator control center that can control a second Facility. Specifically, this change would now expand what constitutes a GOP control center to facilities that operate two or more low impact generators at separate locations. Additionally, we do not support the use of the term rooms or "Cyber Assets". To address our concerns, we offer the following edits (in boldface):

Control Center - One or more **facilities** where a responsible entity **houses** operating personnel to monitor and control the Bulk Electric System (BES) **facilities** in real-time, as described below, including **BES Cyber Systems** used by **those** operating personnel to monitor and control the BES in real-time. **BES Cyber Systems** used by operating personnel to monitor and control the BES in real-time are generally **located** in a centralized location and exclude field assets such as remote terminal units.

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;
3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or **more separate physical** locations;
4. Transmission Owner **facilities that** have the capability to electronically control Transmission Facilities at two or more **separate physical** locations in real-time; or
5. Operating personnel **who perform the Real-time reliability-related tasks** of a Generator Operator **for** generation Facilities at two or more **separate physical** locations.

Likes 0	
Dislikes 0	

Response

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh

Answer	No
Document Name	

Comment

NST disagrees with the proposed changes to the definition of "Control Center" for the following reasons:

> NST has helped a multitude of Registered Entities achieve and maintain compliance with the CIP Standards, beginning with Version 1, and we have yet to interact with one whose Subject Matter Experts were unclear about the meaning of "facility" in the Control Center definition that became effective July 1, 2016. We have likewise encountered no confusion about what a "data center" is. NST acknowledges the field test report's statement that a number of TOs "have struggled to interpret the Control Center definition," but we also note the approximately 20 TOs that provided information during the study represents a very small percentage of Registered Entities subject to the CIP Standards.

> NST believes the proposed change from "data centers" to "spaces" to connote where a Control Center's Cyber Assets might reside reduces rather than increases clarity. What, exactly, is a "space"?

> The proposed changes fail to address an important question that the advent of requirements applicable to communication links between Control Centers (CIP-012) brought to the fore: Is a data center that houses some of a Control Center's Cyber Assets (e.g., SCADA/EMS servers) itself a Control Center? A CIP-012-1 webinar presented by NERC and the six Regional Entities on June 2, 2022 stated, "A data center is a Control Center." NST considers this assertion to be both incorrect and problematic for several reasons, including the fact that while it's possible for a Control Center's operators and the servers they use to be in different Zip Codes, it's also entirely possible for the operators and all the Cyber Assets they need to be in the same room of the same building. Are there TWO Control Centers in the latter instance? Of course not.

NST believes it is essential that this issue be addressed by any attempt to update the current definition of Control Center, and we respectfully submit the following alternate language for the SDT's consideration:

A Bulk Electric System asset used by the operating personnel listed below to monitor and control the Bulk Electric System in real-time. A Control Center includes:
- Workspaces for operating personnel
- Cyber Assets used by operating personnel to monitor and control the BES in real-time. Some of those Cyber Assets may be, in some instances, in a different physical location (e.g., a remote data center) than the operator workspaces

1. Operating personnel who perform the Real-time reliability-related tasks of a Reliability Coordinator;

2. Operating personnel who perform the Real-time reliability-related tasks of a Balancing Authority;

3. Operating personnel who perform the Real-time reliability-related tasks of a Transmission Operator for Transmission Facilities at two or more

locations;

4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time; or

5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more locations in real-time.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports NPCC/RSC's comments.

Likes 0	
Dislikes 0	

Response

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	No
Document Name	

Comment

The standard drafting team has done an excellent job in clarifying a complex definition. The use of one definition for both the control room and associated data center is effective and clear.

There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center; however the generators are individual Facilities and are located over a large physical area.

The following definition is proposed:

4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or

5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.

Likes 0	
Dislikes 0	

Response

Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)

Answer	No
Document Name	

Comment

The ISO/RTO Council (IRC) Standards Review Committee (SRC) is concerned that the phrase "electronically control . . ." in paragraphs 4 and 5 of the proposed Control Center definition does not achieve the purpose described in the Technical Rationale of differentiating between remote control in Real-time and control via instructions issued to field personnel. Specifically, the SRC is concerned that the term "electronically" could cause confusion, as the radios or telephones used to issue instructions to field personnel could be viewed as an electronic form of control, while Real-time control that relies on mechanical or fiber optic means of control might be considered to fall outside the bounds of electronic control.

The SRC proposes that the drafting team consider removing the word "electronically" from paragraphs 4 and 5. The SRC believes that the qualifier "in real-time" at the end of each paragraph should suffice to achieve the goal described in the Technical Rationale. Dispatching field personnel to a location to perform an action would arguably not count as Real-time control, since time would elapse between the issuance and the execution of an instruction while the field personnel travel to the location and execute the actions needed to control the impacted Facility. On the other hand, a scenario in which instructions are being conveyed via radio or telephone to field personnel who are already on-site at a Facility and will execute the instructions within seconds of receiving them might be considered Real-time control, but this may be consistent with the overall purpose of the Control Center definition.

Additionally, the SRC notes that the proposed definition alternates between using the capitalized term "Real-time," which is defined in the NERC Glossary of Terms, and the uncapitalized term "real-time." The SRC requests that the drafting team adopt a consistent capitalization approach to clarify whether the definition from the NERC Glossary of Terms is intended to apply. If the NERC Glossary definition is not intended to apply, or if it is only intended to apply in some locations, the SRC requests that the drafting team use a different term in place of the uncapitalized term "real-time" to avoid confusion with the capitalized term defined in the NERC Glossary.

Finally, in order to provide further clarity, the SRC suggests that the first two sentences of the definition of a Control Center be revised and combined into a single sentence that reads as follows:

Control Center: One or more rooms where a responsible entity hosts any of the operating personnel described in paragraphs 1-5 below who monitor and control or monitor and direct action for the Bulk Electric System (BES) in Real-time, and any spaces that house the Cyber Assets used by operating personnel to monitor and control or monitor and direct action for the BES in Real-time, excluding field assets such as remote terminal units.

Likes 0	
Dislikes 0	

Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	No
Document Name	
Comment	
ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The standard drafting team has done an excellent job in clarifying a complex definition. The use of one definition for both the control room and associated data center is effective and clear. There remains some ambiguity in #4 and #5 of the definition relating to the criteria of two or more locations. For #4 for Transmission Facilities, a line as a single Facility covers a large geographic area. The definition is not clear if a control room can modify operation at the other end of the line, is this a control center? For #5 for generation Facilities, the definition is not clear for dispersed power producing resources such as wind and solar. This should not be considered a control center, however the generators are individual Facilities and are located over a large physical area.	

The following definition is proposed:

4. Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time (a Transmission line counting as a single Facility and location for this purpose); or

5. Operating personnel of a Generator Operator who have the capability to electronically control generation Facilities at two or more aggregate locations in real-time.

Likes 0	
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	

The field test was only conducted and directed at Transmission Operators and Transmission Owners and doesn't consider the impact to registered entities outside of this range. Recommend preserving the previous language and adding additional language to address the Transmission Owner risk(s). Additionally, the expanded wording used to address "data centers" could have unintended consequences such as the potential expansion in scope of applicable Cyber Assets and rooms. An example of excluded field assets is given as the remote terminal units; it's unclear if protection relays and the communication equipment used to provide real-time information to the operating personnel would also fit under this exclusion.

Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	

Duke Energy supports NAGF comments on the Control Center definition and appreciates the work of the Drafting Team, including all the industry engagment through the previous informal comment period. Duke Energy also support's EEI's comments on the concerns regarding scope expansion in the draft language for GOPs. If the Drafting Teams feels that the "associated data center piece" must be expanded on , and that they cannot keep the body of the current definition as NAGF suggests, Duke Energy suggests the following alternative language:

One or more facilities where a responsible entity houses operating personnel who perform the functional entity obligations described below, including locations that contain BES Cyber Systems used by those operating personnel to support the functional entity's capability to monitor and have control authority of the Bulk Electric System (BES) in Real-time.

1.Reliability-related tasks of a Reliability Coordinator,

2. Reliability related tasks of a Balancing Authority,

3. Reliability-related tasks of a Transmission Operator at two or more locations,

4. Reliability-related tasks of a Transmission Owner at two or more locations,

5.Generator Operator having the capability to electronically control generation Facilities at two or more locations.

Likes 0	
Dislikes 0	

Response

Lindsey Mannion - ReliabilityFirst - 10

Answer	Yes
Document Name	

Comment

The current proposed definition of Control Center is very wordy. Consider creating a separate definition of data center leveraging the wording in the current proposed definition of Control Center. This may allow for better overall readability.

Likes 0	
Dislikes 0	

Response

Tracy MacNicoll - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

The drafting team should clarify the last sentence of the core definition. Are field assets such as remote terminal units excluded from the Control Center definition? “Real-time” in 4 and 5 should be capitalized.

Likes 0	
Dislikes 0	
Response	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
While we can agree with the proposed changes we do have a couple suggestions. The last sentence of the proposed first paragraph is "Cyber Assets used by operating personnel to monitor and control the BES in real-time are generally housed in a centralized location and exclude field assets such as remote terminal units." 1. It's not obvious to us the purpose of the words "are generally housed in a centralized location and". Could they be deleted? Also, the term "field assets" is used in that sentence. 2. The October 30th webinar conducted by the SDT included "data aggregators" as a type of field asset. Because of their common use, we recommend adding data aggregators alongside remote terminal units in that text.	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scot Nairn - Bonneville Power Administration - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
Please see comments by Marty Hostler, NCPA. Thanks.	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

Texas RE is concerned the proposed definition of Control Center inherently scopes Control Center's down from a "location" (facilities) perspective to a "room" perspective. This could be problematic for other CIP and O&P standards such as CIP-014-2 and TOP-001-5. Texas RE recommends the definition clarify that the entire applicable facility is included, rather than simply one space within the facility.

For example, if the proposed definition were adopted, in CIP-014-2, only the Control Center "room" would need to be evaluated for potential threats and vulnerabilities of a physical attack. This leaves out other areas of that facility which should also be afforded the protections of CIP-014-2.

As a second example, if the proposed definition were adopted, in TOP-001-5, only the Control Center "room" would need to have data exchange capabilities, with redundant and diversely routed data exchange infrastructure, which leaves out other areas of the facility that should have data exchange capabilities, such as the data center.

Likes 0	
Dislikes 0	
Response	

2. The SDT added the following preface to Criteria 2.11, 2.12 and 2.13: "Each BES Cyber System, not included in Section 1 above, used by and located at any of the following:". This was intentional, to make clear that the BES Cyber Systems to consider differ between Control Centers and other assets such as Transmission stations and Generation resources. In alignment with Part 1 of Attachment 1, BES Cyber Systems 'used by and located at' Control Centers need to be considered. This prevents expanding from Control Centers down into field assets. With respect to other assets, it is BES Cyber Systems 'associated with' the assets that are considered. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Megan Melham - Decatur Energy Center LLC - 5	
Answer	No
Document Name	
Comment	
The proposed language does not provide additional clarification. The statement above Criteria 2.11, 2.12, and 2.13 is already at the top of Section 2 above Criteria 2.1 and is redundant with verbiage already included in each of the three criteria where it states "…that is not already included in High Impact Rating (H) above…". Recommend removing the preface and leaving Criteria 2.11, 2.12, and 2.13 as written.	
Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	No
Document Name	
Comment	
The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language	

prefacing section 2.11, 2.12, and 2.13: “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above,”.	
Likes 0	
Dislikes 0	
Response	
Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy supports EEI comments.	
Likes 0	
Dislikes 0	
Response	
Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro	
Answer	No
Document Name	
Comment	
The initial scope of the 2021-03 SAR initially authorized changes to 2.12, and 2.11 and 2.13 were subsequently added.	

The added sentence after Criterion 2.10 does not seem to add value since there the Section 2 Medium Impact Rating already includes the “associated with” wording. We understand that the intention is to group the Control Centers from other assets. BC Hydro suggests organizing the Attachment 1 by groups to clarify the scope and application.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports NAGF's comments on this project	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	
Comment	

Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with NAGF comments: The NAGF recommends the exclusion of the proposed language as it does not provide additional clarification due to the redundancy of language prefacing section 2.11, 2.12, and 2.13. “Each Control Center or backup Control Center, not already included in High Impact Rating (H) above”.	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute” Comments: In the project SAR, bullet 1 under the Project Scope section, the SDT was asked to “[c]larify VAR-002-4.1 Requirement R3 in regards to whether the GOP of a dispersed power resource must notify its associated TOP of a status change of a voltage controlling device on an individual generating unit, for example if a single inverter goes offline in a solar PV resource.” This change was recommended to provide uniformity between wind turbine plants with other dispersed power producing resources. We support this change and recommend the SDT include a similar reporting exception for Requirement R3 to what exists in VAR-002-4.1, Requirement R4 as proposed in both the supporting white paper for this project and the Project SAR. EEI also asked the SDT to remove proposed Requirement R3 language that states “in a mutually-agreed communications method”, because this language serves no reliability benefits but adds unnecessary compliance obligations; i.e., the need to document that an agreement was developed, mutually agreed to and was followed.	
Likes 0	

Dislikes 0	
Response	
Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	No
Document Name	
Comment	
Instead of grouping Criteria 2.11, 2.12 and 2.13 in Section 2, Tacoma Power recommends creating a new Section in CIP-002 to house these criteria. If the intent of the SDT is to have these three criteria grouped separately from the other medium impact criteria in Section 2, grouping would be served better by creating a new separate section.	
Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Sunflower votes no due to our disagreement with making modifications to the Control Center definition.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 4	
Answer	No
Document Name	
Comment	
We agree with the proposed preface to Criteria 2.11, 2.12, and 2.13, however feel some additions need to be made to clarify “used to perform the functional obligation of” throughout the Attachment 1 criteria. The SAR on page 3, indicates that the language scope "perform the functional obligation of" needs clarification throughout the Attachment 1 criteria, not	

just IRC 2.12.

In IRC 2.11 clarification is needed for "used to perform the functional obligation". In a FERC 2017 Audit lessons learned document, which auditors have referenced, during past audits and conferences/webinars, it claims that non-BES assets are to be included in the aggregate net real power calculation. This puzzles us and others as it is unclear to how a GOP performs functional obligations for non-registered non-BES generators, which have no NERC GOP functional obligations.

The IRC 2.11 clearly states to us that you aggregate the net real power of generators for which the GOP performs functional obligations. Since non-BES generators have no functional obligations they are not to be included.

Regardless, we include non-BES generation in our IRC 2.11 calculations, even though we do not believe it is required to do so, simply because auditors have told us that we have to, based on the aforementioned 2017 FERC Audit Lessons Learned document.

We suggest that the following language be added in the aforementioned proposed preface language or at the end of IRC 2.11. "Only BES generation is to be aggregated when determining the net real power capability, non-BES generation is not to be included".

Or restate, in the aforementioned preface, that GOPs do not perform functional obligations for non-BES assets, and non-BES generation is not to be included when determining a GOPs impact rating in IRC 2.11. We realize that this may seem repetitive and/or intuitive to the SDT but, per the aforementioned 2017 Lessons Learned document, others may not have known the non-BES assets have no functional obligations. And that a GOP is not accountable to perform GOP functional obligations for a non-BES generator that has no GOP functional obligations. Consequently, GOPs do not include non-BES generation when calculating net real power in IRC 2.11.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

EEI supports this proposed change.

Likes 0	
Dislikes 0	

Response

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster

Answer	Yes
Document Name	

Comment

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

Likes 0	
Dislikes 0	

Response
Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment
Exelon supports the comments submitted by the EEI for this question.

Likes 0	
Dislikes 0	

Response
Andrew Smith - APS - Arizona Public Service Co. - 5

Answer	Yes
Document Name	

Comment
AZPS agrees with the proposed changes.

Likes 0	
Dislikes 0	

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

Answer	Yes
Document Name	

Comment
Southern Company agrees with the comments from EEI.

Likes 0	
Dislikes 0	
Response	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
NEE supports the change and is in agreement with EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	Yes
Document Name	
Comment	
Exelon is responding in support of EEI's response to this question.	
Likes 0	
Dislikes 0	
Response	
Alison MacKellar - Constellation - 5	
Answer	Yes
Document Name	
Comment	
Affirmative specifically for Criteria 2.11. Alison Mackellar on behalf of Constellation Segments 5 and 6	
Likes 0	

Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

FirstEnergy supports this change.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	Yes
Document Name	

Comment

This change helps to group Control Centers from other assets, but ACES suggests grouping Attachment 1 by registration or adding a matrix by registration to make classification easier, particularly with the potential introduction of new NERC registrations, such as IBR.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment

AEPC signed on to ACES comments below:

This change helps to group Control Centers from other assets, but ACES suggests grouping Attachment 1 by registration or adding a matrix by registration to make classification easier, particularly with the potential introduction of new NERC registrations, such as IBR.

Likes 0	

Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	
Answer	Yes
Document Name	
Comment	
Affirmative specifically for Criteria 2.11. Kimberly Turco on behalf of Constellation Segments 5 and 6	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Buckeye supports the comments made by ACES: This change helps to group Control Centers from other assets, but ACES suggests grouping Attachment 1 by registration or adding a matrix by registration to make classification easier, particularly with the potential introduction of new NERC registrations, such as IBR.	
Likes 0	
Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Standifur - Austin Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Tracy MacNicoll - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Scot Nairn - Bonneville Power Administration - NA - Not Applicable - WECC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group	
Answer	Yes
Document Name	
Comment	
Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	
Document Name	
Comment	
Please see comments by Marty Hostler, NCPA. Thanks.	
Likes 0	
Dislikes 0	
Response	

3. The SDT revised CIP-002-Y Attachment 1 Criterion 2.12 based on data obtained from the field test and industry comments from the informal comment period. Do you agree with the proposed changes? If not, please provide the basis for your disagreement and an alternate proposal.

Marty Hostler - Northern California Power Agency - 4

Answer	No
Document Name	

Comment

Yes. the proposal is ok.

Likes 0	
Dislikes 0	

Response

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO

Answer	No
Document Name	

Comment

The definition of a control center add in #4 “Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;” to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact.

The following wording is suggested for 2.12 to resolve this:

Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	No
Document Name	

Comment

The definition of a control center add in #4 “Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;” to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact.

The following wording is suggested for 2.12 to resolve this:

Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Jennie Wike - Jennie Wike On Behalf of: Hien Ho, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; John Nierenberg, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; Terry Gifford, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power

Answer	No
Document Name	

Comment

The Exclusion language in Criterion 2.12 could effectively allow up to 1499MW of generation to offset any export, especially when that generation is not within the load center. Under the current language entities with a significant aggregate weighted value several times the 6000 limit would be allowed to exclude a local system that has a “net” export less than 75MW if they have generation to offset as a negative export (import). Tacoma Power recommends removing the word “net” from the Exclusion to resolve this issue.

Suggested Exclusion language:

“Exclusion: BES Transmission Lines monitored and controlled by the Control Center or backup Control Center may be excluded from the “aggregate weighted value” calculation if they are part of a local system that is operated at less than 300kV, where the **export** from the local system does not exceed 75 MW during non-Energy Emergency Alert (EEA) conditions. The **export** is based on the hourly integrated values for the most recent 12-month period.”

Likes 2	Snohomish County PUD No. 1, 6, Liang John; LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	

Response

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	

"See comments submitted by the Edison Electric Institute"

Comments: EEI does not support the deletion of the bulleted reporting exception for individual generating units of dispersed power producing resources made to Requirement R4. The SAR scope asked the SDT to clarify whether a similar exception should be added to Requirement R3, not delete the reporting exception already contained in Requirement R4. Moreover, there is no justification provided for removing this reporting exception. The SDT should restore the bulleted reporting exception for individual generating units of dispersed power producing resources as currently contained in VAR-002-4.1.

EEI also asked the SDT to remove proposed Requirement R4 language that states "in a mutually-agreeable communications method", because this language serves no reliability benefits but adds unnecessary compliance obligations; i.e., the need to document that an agreement was developed, mutually agreed to and was followed.

Likes 0	
Dislikes 0	
Response	
Claudine Bates - Black Hills Corporation - 6	
Answer	No
Document Name	
Comment	

Black Hills Corporation is in agreement with EEI's comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."

Likes 0	
Dislikes 0	
Response	
Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt	
Answer	No
Document Name	

Comment	
Black Hills Corporation is in agreement with EEI's comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	
Micah Runner - Black Hills Corporation - 1	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI's comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	
Ben Hammer - Western Area Power Administration - 1	
Answer	No
Document Name	
Comment	
The definition of a control center add in #4 "Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;" to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact. The following wording is suggested for 2.12 to resolve this: Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or	

with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	No
Document Name	
Comment	
AEPC does not completely agree with the changes. Specifically, because the implementation of the exceptions are non-standard to the CIP-002 inclusion/exclusion process(es). AEPCs objection is very similar to ACES’ feedback below, but ACES chose to be in favor of the changes because the exception language has no impact to the original weighting from the previously passed CIP-002-6 and gave entities the flexibility to define “local network”. ACES Feedback: ACES agrees with the changes, but proposes additional clarity. The SDT did a great job with the additional exception from CIP-002-6, but failed to define a “local network”. There is documentation in the technical rationale, but feel we need crystal clear guidance when potentially excluding a BES Transmission Line which potentially make a Control Center medium or low impact.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	No
Document Name	
Comment	
Ameren supports EEI's comments on this project	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	

Answer	No
Document Name	
Comment	

ACES agrees with the changes, but proposes additional clarity. The SDT did a great job with the additional exception from CIP-002-6, but failed to define a “local network”. There is documentation in the technical rationale, but feel we need crystal clear guidance when potentially excluding a BES Transmission Line which potentially make a Control Center medium or low impact.

ACES’ Member Arizona G&T Cooperatives (AEPC) does not completely agree with the changes. Specifically, because the implementation of the exceptions are non-standard to the CIP-002 inclusion/exclusion process(es).

Likes 0	
Dislikes 0	
Response	

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	No
Document Name	
Comment	

Based on the feedback provided to Question #1 above and the comments provided during the informal commenting period of this Project 2021-03 CIP-002-Y changes in July 2023. BC Hydro maintains the position that these changes are introducing ambiguities to the Control Center definition and its application, and request to kindly address the comments provided.

Likes 0	
Dislikes 0	
Response	

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

Answer	No
Document Name	
Comment	

FE has no objection to the proposed criteria.

Likes 0	
Dislikes 0	
Response	

Sheila Suurmeier - Black Hills Corporation - 5	
Answer	No
Document Name	
Comment	
Black Hills Corporation is in agreement with EEI's comments: "The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."	
Likes 0	
Dislikes 0	
Response	
Tristan Miller - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE is in support of the comments as submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Kinte Whitehead - Exelon - 3	
Answer	No
Document Name	
Comment	
Exelon is responding in support of EEI's response to this question.	
Likes 0	
Dislikes 0	
Response	

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
NEE supports EEI's comments: The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Southern Company agrees with the comments from EEI.	
Likes 0	
Dislikes 0	
Response	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas & Electric (SIGE) is in support of the comments as submitted by the Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	

Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS does not agree with the proposed changes but does supports the comments that were submitted by EEI on behalf of their members related to the exclusion of transmission lines below 100kv except those that were identified through appendix 5C of the Rules of Procedure as BES Transmission Lines. As currently written there needs to be clarity for criteria for lines below 100kv.	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	No
Document Name	
Comment	
Exelon supports the comments submitted by the EEI for this question.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the Edison Electric Insititute (EEI) for question #3.	
Likes 0	
Dislikes 0	
Response	

Jeremy Lawson - Northern California Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
See comments by Marty Hostler, NCPA.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center.	
Likes 0	
Dislikes 0	
Response	
Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	No
Document Name	
Comment	
NST considers the "Exclusion" language to be insufficiently clear (e.g., What is a "local system"?), and we believe the SDT should endeavor to simplify a requirement that appears to require a set of highly complex calculations.	
Likes 0	
Dislikes 0	
Response	

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	No
Document Name	
Comment	

The definition of a control center add in #4 "Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;" to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered medium impact.

The following wording is suggested for 2.12 to resolve this:

Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an "aggregate weighted value" exceeding 6000 according to the table below and subject to the listed exclusion. The "aggregate weighted value" for a Control Center or backup Control Center is determined by summing the "weight value per characteristic" shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.

Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE is concerned that the way of calculating the risk may not cover all scenarios and does not account for differences in Transmission lines. Texas RE has taken the position that that BCS used to perform the functional obligations of a Transmission Operator should remain categorized as medium impact or high impact. The risk the BCS at a Control Center poses to the reliable operation of the BES is not easily covered by counting the quantity of transmission lines operated. Two Control Centers operating the same number of transmission lines may pose very different risks to the BES. For example, if one Control Center is predominantly operating Transmission lines at substations interconnected with Generation Facilities it may pose more risk than a Control Center operating Transmission lines at substations that are not interconnected with Generation Facilities.

Texas RE proposes the following language for criterion 2.12:

Each Control Center or backup Control Center operated by a Transmission Operator or owned by a Transmission Owner.

Likes 0	
Dislikes 0	
Response	

Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	

Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
The definition of a control center add in #4 “Operating personnel of a Transmission Owner who have the capability to electronically control Transmission Facilities at two or more locations in real-time;” to include a transmission owner control center. The high impact rating in 1.3 applies only to control centers operated by a Transmission Operator. For criterion 2.12 there is then a gap, where a Transmission Owner control center that can control a 500kV line (or that meets other criteria for High Impact outlined in 1.3) will not be included in 2.12 and will not be considered Medium impact. The following wording is suggested for 2.12 to resolve this: Each Control Center or backup Control Center, operated by a Transmission Operator or owned by a Transmission Owner, that is not already included in High Impact Rating (H) above, with the capability to electronically control one or more of the assets that meet criterion 2.2, 2.4, 2.7, 2.8, 2.9, or 2.10, or with an “aggregate weighted value” exceeding 6000 according to the table below and subject to the listed exclusion. The “aggregate weighted value” for a Control Center or backup Control Center is determined by summing the “weight value per characteristic” shown in the table for each BES Transmission Line monitored and controlled by the Control Center or backup Control Center.	
Likes 0	

Dislikes 0	
Response	
Ellese Murphy - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	No
Document Name	
Comment	
We support EEI comments on Attachment 1 Criterion 2.12.	
Likes 0	
Dislikes 0	
Response	
Paul Mehlhaff - Sunflower Electric Power Corporation - 1	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	Yes
Document Name	
Comment	
Buckeye supports the comments made by ACES: ACES agrees with the changes, but proposes additional clarity. The SDT did a great job with the additional exception from CIP-002-6, but failed to define a “local network”. There is documentation in the technical rationale, but feel we need crystal clear guidance when potentially excluding a BES Transmission Line which potentially make a Control Center medium or low impact.	
Likes 0	

Dislikes 0	
Response	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
We do not support EEI comments. Exclusions are built into the BES definition. The table used to calculated weighted value imposes the definition in the table header.	
Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	Yes
Document Name	
Comment	
Use of the undefined term "backup" Control Center is unnecessary, versus simply utilizing the defined term "Control Center." For clarification, for 500kV and above, add the text "automatic high impact" rather than stating "0".	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Sandra Pacheco - Silicon Valley Power - City of Santa Clara - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
VAL GUZMAN - Silicon Valley Power - City of Santa Clara - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
David Owens - Gainesville Regional Utilities - 1,3,5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Lindsey Mannion - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scot Nairn - Bonneville Power Administration - NA - Not Applicable - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karen Artola - CPS Energy - 1,3,5 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tracy MacNicoll - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Israel Perez - Israel Perez On Behalf of: Mathew Weber, Salt River Project, 3, 1, 6, 5; Sarah Blankenship, Salt River Project, 3, 1, 6, 5; Thomas Johnson, Salt River Project, 3, 1, 6, 5; Timothy Singh, Salt River Project, 3, 1, 6, 5; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Standifur - Austin Energy - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
John Daho - MEAG Power - 1,3 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Magruder - Avista - Avista Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Monika Montez - California ISO - 2 - WECC, Group Name ISO/RTO Council Standards Review Committee (SRC)	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Megan Melham - Decatur Energy Center LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kimberly Turco - Constellation - 6	

Answer	
Document Name	
Comment	

Constellation has no comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6

Answer	
Document Name	
Comment	

Please see comments by Marty Hostler, NCPA. Thanks.

Likes 0	
Dislikes 0	
Response	

Alison MacKellar - Constellation - 5

Answer	
Document Name	
Comment	

Constellation has no comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	
Response	

Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	
WEC Energy Group has comment on Attachment 1 Criterion 2.12 as it specifically applies to TO/TOP functions/registrations	
Likes 0	
Dislikes 0	
Response	
Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF has no comment as Criterion 2.12 applies specifically to TO/TOP registrations.	
Likes 0	
Dislikes 0	
Response	

4. Provide any additional comments for the SDT to consider, if desired.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	
Comment	
See comments submitted by the Edison Electric Institute	
Likes 0	
Dislikes 0	
Response	
Lindsay Wickizer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	
Comment	
The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.	
Likes 0	
Dislikes 0	
Response	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	
Document Name	
Comment	
The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months, or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come into effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This	

would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	
Document Name	
Comment	
OPG supports NPCC/RSC's comments.	
Likes 0	
Dislikes 0	
Response	

Roger Fradenburgh - Roger Fradenburgh On Behalf of: Nick Lauriat, Network and Security Technologies, 1; - Roger Fradenburgh	
Answer	
Document Name	
Comment	
(No further comment)	
Likes 0	
Dislikes 0	
Response	

Wayne Sipperly - North American Generator Forum - 5 - MRO,WECC,Texas RE,NPCC,SERC,RF	
Answer	
Document Name	
Comment	
The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.	

Likes 1	LaKenya Vannorman, N/A, Vannorman LaKenya
Dislikes 0	
Response	
Alain Mukama - Hydro One Networks, Inc. - 1	
Answer	
Document Name	
Comment	
Request clarification of “BES Transmission Line”. “BES” is defined as Transmission elements operated at 100 kV or higher, so “BES Transmission Line” is expected to be Transmission Lines operated at 100 kV or higher. However, the new 2.12 includes weight value below 100 kV. Please define or explain.	
Likes 0	
Dislikes 0	
Response	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	
Document Name	
Comment	
Evergy supports and incorporates by reference the comments of the MRO NSRF for question #4.	
Likes 0	
Dislikes 0	
Response	
Nicolas Turcotte - Hydro-Quebec (HQ) - 1	
Answer	
Document Name	
Comment	
A negative vote was cast in error. We support the changes.	

Likes 0	
Dislikes 0	
Response	
Christine Kane - WEC Energy Group, Inc. - 3, Group Name WEC Energy Group	
Answer	
Document Name	
Comment	

WEC Energy Group supports the following comment drafted by the NAGF:

"The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities."

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	
Document Name	
Comment	

No additional comments.

Likes 0	
Dislikes 0	
Response	
Kent Feliks - AEP - 3	
Answer	
Document Name	
Comment	

Understanding of the proposed revisions would be greatly enhanced by providing Implementation Guidance.

Likes 0	
Dislikes 0	

Response

Alison MacKellar - Constellation - 5

Answer	
Document Name	

Comment

Constellation has no additional comments.

Alison Mackellar on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Sheila Suurmeier - Black Hills Corporation - 5

Answer	
Document Name	

Comment

Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.”

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Adrian Andreoiu - BC Hydro and Power Authority - 1, Group Name BC Hydro

Answer	
Document Name	

Comment

BC Hydro recognizes the effort done by this drafting team to encapsulate the changes via Project 2021-3 CIP-002-Y and look forward to the resolution of the comments and suggestions provided.

Additionally with respect to the Implementation Plan there are multiple time frames allowed for the implementation period per the new changes to CIP-002-Y standard e.g., 12 months for net new BCS (high/medium) and 24 months for entities first time identified high or medium impact BCS.

BC Hydro recommends that in all cases including a net new high/medium impact BCS, newly categorized high impact BCS from medium impact BCS and newly categorized medium impact BCS implementation time should be a minimum of 24 months.

For instance, in cases where existing assets are newly identified as Control Centres as a result of the new Glossary and CIP-002 standard revisions which in turn results in the identification of newly categorized high impact BCS from medium impact BCS and newly categorized medium impact BCS BES Cyber Systems there should be a minimum of 24 months to comply with the breadth of applicable CIP standards. This would not be limited to only those cases that meet criterion 2.12 but other impact rating criterion explicitly associated with Control Centre BES Cyber Assets (e.g. high impact rating criterion 1.1 through 1.4, other medium impact rating criterion, and low impact rating criterion).

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6

Answer	
Document Name	

Comment

Please see comments by Marty Hostler, NCPA. Thanks.

Likes 0	
Dislikes 0	

Response

Michael Whitney - Northern California Power Agency - 3

Answer	
Document Name	

Comment

See comments by Marty Hostler, NCPA.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP

Answer	
Document Name	

Comment

No additioinal comments.

Likes 0	
Dislikes 0	

Response

Teresa Krabe - Lower Colorado River Authority - 5

Answer	
Document Name	

Comment

LCRA believes that changing the definition of Control Center will have unintended consequences. This change impacts the applicability of CIP-012 and may impact additional Operations and Planning Standards.

Likes 0	
Dislikes 0	

Response

Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators

Answer	

Document Name	
Comment	
ACES would like to thank the SDT for its continued hard work.	
Likes 0	
Dislikes 0	
Response	
David Jendras Sr - Ameren - Ameren Services - 3	
Answer	
Document Name	
Comment	
Ameren supports NAGF's comments on this project	
Likes 0	
Dislikes 0	
Response	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	
Document Name	
Comment	
LCRA believes that changing the definition of Control Center will have unintended consequences. This change impacts the applicability of CIP-012 and may impact additional Operations and Planning Standards.	
Likes 0	
Dislikes 0	
Response	
Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1	
Answer	
Document Name	
Comment	

AEPC appreciates the opportunity to comment and appreciates the hard work by the SDT.

Likes 0	
Dislikes 0	
Response	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	
Document Name	
Comment	

Suggest that guidance be given on the result of combining the “BES” and the “Transmission Line” NERC defined terms. While the BES term allows for Transmission lines less than 100kV the “Transmission Lines” sets a lower limit of 69kV. Request clarification for a 69 kV line that meets the Transmission Line definition but not the BES definition.

This is not specific to this question and may identify an issue that is not technically possible but there is a gap between the X99 and Y00 “Characteristics of Line” levels. A 199.5kV line is not rated on this table.

Request explicit explanation (in the Standard) of the weighted value of zero for “Each BES Transmission Line 500 kV and above.” (see Criterion 2.5) We agree with the weighted value. Please correct as needed – we understand that a Control Center with such a Tranmission Line is High Impact.

The language for the exemption seems to allow for the exclusion of a Controls Center as Medium impact if the load in a set of BES Transmission Lines offsets the generation in another set of BES Transmission Lines, even if these lines are not tied together within the Transmission system controlled by the Control Center.

Does the “net” in “net export” apply to the net total for all applicable BES Transmission Lines at a single point in time or the net export of each of these lines over the 12 month period.

The 12 month period portion of the language makes it unclear how new transmission lines are handled even if it is known that they will increase the “net export” beyond the 75MW threshold.

The SDT should provide clarity on if a change in the “net export” fluctuates around or exceeds for the first time, the 75MW threshold. When is exceeding the threshold an “unplanned change”, allowing for a 2 year implementation and when is it a “planned change” requiring the medium impact implementation to be completed before the threshold is exceeded? If an exempt Control Center looses the exemption, starts the implementation period, gains the exemption before the implementation is completed and then looses the exemption, if there are not other medium impact programs in place, do they always get 2 year to either implement the plan or pray that they gain the exemption before the implementation period is over?

Likes 0	
Dislikes 0	

Response

Tracy MacNicoll - Utility Services, Inc. - 4

Answer	
Document Name	

Comment

The way **“Phased-in Implementation Date for CIP-002-Y, Requirement R1, Attachment 1 Criterion 2.12”** in the implementation plan is currently written, entities may have between 9 and 24 months following their first CIP-002-Y assessment to implement a higher impact level categorized BES Cyber System. This is due to the fact that they can perform their initial assessment up to 15 months following the Effective Date of CIP-002-Y based on when they performed their previous assessment. The drafting team should consider starting the 24-month clock once an entity performs its initial CIP-002-Y assessment, not based on the effective date of CIP-002-Y as it is currently written.

Entities that identify their first high impact or medium impact BES Cyber System, under their initial CIP-002-Y assessment, should be awarded the full 24 month compliance implementation per the last row of the table on page 4 of 5 of the Implementation Plan regardless of if they perform that assessment 1 month or 14 months following the Effective Date of CIP-002-Y.

Likes 0	
Dislikes 0	

Response

Kimberly Turco - Constellation - 6

Answer	

Document Name	
Comment	

Constellation has no comments.

Kimberly Turco on behalf of Constellation Segments 5 and 6

Likes 0	
Dislikes 0	

Response

Karen Artola - CPS Energy - 1,3,5 - Texas RE

Answer	
Document Name	

Comment

Please provide clarification on the intent of the retirement of Sections in CIP-002-5.1a labeled “Background” and “Guidelines and Technical Basis” from the CIP-002-Y proposed draft language to the Technical Rationale Project 2021-03 CIP-002 | Reliability Standard CIP-002-Y document. Especially of concern is the retirement of the concept of BES reliability operating service (BROS) from the CIP-002 Cyber Security-BES Cyber System Categorization standard entirely. The BROS is essential for the proper classification/categorization of BES Cyber Systems (BCS) and in determining the overall BES impact of those BCS. The ongoing use of the BROS in BCS categorization and BES impact rating determination may have been overlooked by the Project 2021-03 CIP-002 SDT based on the statement: "...to preserve any historical references."

Likes 0	
Dislikes 0	

Response

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 0	
Dislikes 0	

Response

Micah Runner - Black Hills Corporation - 1

Answer	
Document Name	

Comment

Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.”

Likes 0	
Dislikes 0	

Response

Rachel Schuldt - Rachel Schuldt On Behalf of: Josh Combs, Black Hills Corporation, 5, 6, 1, 3; - Rachel Schuldt

Answer	
Document Name	

Comment

Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.”

Likes 0	
Dislikes 0	

Response

Claudine Bates - Black Hills Corporation - 6

Answer	
Document Name	

Comment

Black Hills Corporation is in agreement with NAGF comments: “The NAGF is concerned that there may be unintended consequences that would impact Generator Operators based on the proposed revision to the Control Center definition. Without inclusion of Generator Operators in the field test, this may

increase the burden of compliance on Generator Operators without directly addressing risk(s) to reliability and security of their Facilities.”	
Likes 0	
Dislikes 0	
Response	
Teresa Kihara - Teresa Kihara On Behalf of: Truong Le, Acciona Energy North America, 5; - Teresa Kihara	
Answer	
Document Name	
Comment	
Under the definition of a control center, please define or clarify what is consider “in real-time". Is real-time considered within 15 minutes impact, 5 minutes, or immediate?	
Likes 0	
Dislikes 0	
Response	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	
Document Name	
Comment	
“See comments submitted by the Edison Electric Institute” While EEI does not oppose the use of the term “generator resource(s)” in place of generator, it does not add any enhanced clarity to the language of the VAR-002, noting that the term generator is well understood in the industry.	
Likes 0	
Dislikes 0	
Response	
Ryan Strom - Ryan Strom On Behalf of: Carl Spaetzel, Buckeye Power, Inc., 4, 3, 5; Jason Procuniar, Buckeye Power, Inc., 4, 3, 5; Kevin Zemanek, Buckeye Power, Inc., 4, 3, 5; - Ryan Strom, Group Name Buckeye Power Group	
Answer	
Document Name	
Comment	

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Anna Martinson - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO Group

Answer	
Document Name	

Comment

The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 1	Central Hudson Gas & Electric Corp., 1, Ridolfino Michael
Dislikes 0	

Response

Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO

Answer	
Document Name	

Comment

The implementation plan presents a set of scenarios whereby the implementation of the new standard can be 3 months, 12 months or 24 months. This includes a different categorization of planned and unplanned changes, however the criteria for planned and unplanned is not clear. It is possible that an entity has been planning a change for some time, for example the construction of a new transmission line. The standard may come in to effect just before the project is complete, affecting the implementation timeline. As an alternative, a time frame of 24 months for all entities is suggested. This would not have a major impact to reliability as it would only affect changes that were planned that would take less than 24 months to complete.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 4

Answer	
Document Name	
Comment	

The SAR indicates to clarify "perform the functional obligation of " throughout the Attachment 1 criteria. See proposed clarifications in response 2 above.

If the SDT is not willing to make said clarification changes then please inform us where NERC specifically lists functional obligations associated with non-registered non-BES generation. The standard we believe already clearly states BES throughout it, but oblivious some auditors have made an interpretation that we are being subject to, and should not be subject to.

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1	
Answer	
Document Name	
Comment	

This standard will burden smaller utilities (TOs) who have minimal transmission assets but who will be required to assess their system annually (every 15 months) to show their newly defined Control Centers will fall under the mathematical threshold of applicability. It will also create a path where the new definition of a Control Center may risk the small Transmission Owners' exposure to other standards regarding NERC System Operator Certification, and other related standards.

Likes 0	
Dislikes 0	
Response	

Comment submitted by Associated Electric Cooperative, Inc.

"The aggregate weighted table should also include an Exclusion for all transmission lines below 100kV, except those that have been identified, through Appendix 5C (PROCEDURE FOR REQUESTING AND RECEIVING AN EXCEPTION FROM THE APPLICATION OF THE NERC DEFINITION OF BULK ELECTRIC SYSTEM) of the Rules of Procedure as BES Transmission Lines. As currently shown, and without clarifying language, it could be understood to mean that all transmission lines below 100kV should be counted in the aggregated weight of a Control Center or backup Control Center."

Comments submitted by SERC

Question 1

SERC appreciates the work of the SDT on this long-running project, and has the following comments on the Control Center definition changes:

- The use of the word 'generally' in a Glossary definition lacks clarity and could lead to inconsistent application among Responsible Entities.
- It is unclear what security principle or finding from the field study/trial excludes 'field assets' such as:
    - data aggregation sites or data acquisition nodes,
    - tie line meters and their data,
    - synchophasors and their data,
    - Cyber Assets used to provide a wide area view, such as frequency monitor.
    - or other technologies such as devices used for monitoring or updating dynamic line ratings under Order 881 and their data
    - from consideration as BES Cyber Assets, since they ultimately exist to provide the information used by the Control Center and its operating personnel to reliably operate the BES. These Cyber Assets are typically not considered by other Attachment 1 criteria since while they are **located at** substations and generation Facilities, the reliability function they serve is to provide data for Control Centers. Suggest that if the SDT wishes to limit the location of BES Cyber Assets associated with Control Centers, the inclusion of ‘used by and located at’ which is added before Attachment 1 Criterion 2.11, 2.12, and 2.13 in the CIP-002-Y draft accomplishes this.
- The phrasing requiring 'monitor and control' and the description of the exclusion of voice/radio only Control Centers would seem to eliminate most Reliability Coordinator control centers from meeting the glossary term, as RCs do monitor but do not control the BES in real-time, except primarily through the use of voice instructions and electronic communications (such as RCIS) that are excluded from this standard. While Attachment Criterion 1.1 does explicitly call on Control Centers performing the functional obligations of an RC, by the letter of the new definition which includes ‘monitor and control’ most RCs could exclude themselves. Suggest changing ‘monitor and control' phrasing to either ‘monitor or control’ or ‘monitor and/or control’.
- The exclusion of Cyber Assets which only 'monitor' but do not 'monitor and control' does not seem to align with the goal of reliably operating the Interconnection(s), as control of Facilities without accurate monitoring data does not lead to secure and reliable operations. Suggest that instead the 'monitor and control the BES in real-me' phrasing be directed instead at Cyber Assets which either monitor or control and are used to accomplish or achieve compliance with NERC O&P standards with a real-me horizon, as described in the 1-5 numbered items in the definition. This may also eliminate some TO control centers who perform the monitoring functions of the TOP but to operate breakers at up to 500kV use interpersonal communication to member cooperative control rooms which have direct control of the 100-500kV breakers via SCADA to the RTU. There are other instances in the present time where the monitoring and control functional obligations of Transmission Operation are divided between multiple different NERC Responsible Entities and service providers, each of which provide part of the composite actions which satisfy the functional obligations of the RC, BA, TOP, and GOP during normal and emergency operations. Suggest changing ‘monitor and control' phrasing to either ‘monitor or control’ or ‘monitor and/or control’ to allow for this flexibility without risking a miss in categorizing a BES Cyber Asset/System.
- The change from facilities to 'rooms' may cause confusion or misapplication for other CIP and O&P standards which came after Version 5 such as CIP-012-1 and others in the COM, EOP, IRO, and TOP families since changing the Control Center definition will affect more than just Transmission Owners. Suggest research be done to understand if knock-on effects in complying with these standards will occur.
- The shifting case of the phrase ‘Real-time’ in Definition items 1, 2, and 3 and ‘real-time’ in definition items 4 and 5 causes confusion as to the nature of the tasks it includes. Furthermore, the NERC glossary term ‘Real-time’ is *Present time as opposed to future time*. Is the

intent of the various phrasings of real-time to indicate only actions required at the (instantaneous) present, or does it refer instead to the NERC Time Horizon of Real-Time operations of actions within one hour, especially in the domain of monitoring?

- The Control Center definition removes the "including their associated data centers". This is a major security gap that should be corrected.

Question 2
No additional comments on item #2.

Question 3
SERC appreciates the work of the SDT on this long-running project, and has the following comments on the changes to the Attachment 1 criteria:

- Has the drafting team considered how an entity would demonstrate the net export during non- EEA conditions? Is this creating more burden on the entity to generate a new value? What would happen if one year this is 74 MW for a line and the following year it crosses 75 MW? Such a situation should be addressed in the implementation plan. Would the entity need to recognize this in its annual application of CIP-002 R2 or immediately upon generation upgrades or installations that may impact the rating? (Would this be planned or unplanned?)
- The use of the net export of 75MW utilizes slightly different criteria than the BES definition 75MVA gross nameplate rating (not net export) traditionally used for registration. What is the reasoning for the different value, and was it derived from the field study?

Question 4
SERC appreciates the work of the SDT on this long-running project, and has the following comments on the additional changes in CIP-002-Y:

- In both 4.1.2.2 and 4.2.1.2, it appears in the redline that the word "Each" was dropped from the beginning of the sentence.
- In Attachment 1, Criteria 2.1 and 2.2, the change from 'those' to 'each discrete' phrasing to address the findings of the CIP-002-5.1a appears to create confusion due to the pluralization of 'BES Cyber Systems' appearing just after. Suggest instead to remove the word 'each', so the sentences would read "the only BES Cyber Systems that meet this criterion are discrete shared BES Cyber System that could…"