Comment Report

Project Name:	2016-02 Modifications to CIP Standards | CIP-012-1 Draft 4
Comment Period Start Date:	5/18/2018
Comment Period End Date:	7/3/2018
Associated Ballots:	2016-02 Modifications to CIP Standards CIP-012-1 AB 4 ST

There were 55 sets of responses, including comments from approximately 149 different people from approximately 101 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Control Center Exemption Language: The SDT drafted Exemption language in the Applicability section specifically for CIP-012-1 to exempt Control Centers that only transmit data pertaining to a single co-located substation or generating plant. Do you agree with this revision? If not, please provide the basis for your disagreement and an alternate proposal.

2. Requirement R1: The SDT modified Requirement R1 to state: "The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between any applicable Control Centers. The Responsible Entity is not required to include oral communications in its plan." Do you agree with this revision? If not, please provide the basis for your disagreement and an alternate proposal.

3. Implementation Plan: The SDT established the Implementation Plan to make the standard effective the first day of the first calendar quarter that is twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate implementation time period is needed, please provide a detailed explanation of actions and time needed to meet the implementation deadline.

4. Technical Rationale: The SDT modified the draft Technical Rationale for CIP-012 to further explain the need for the exemption for certain Control Centers. Do you agree with the explanations and included diagrams in the draft Technical Rationale? If you do not agree, or if you agree but have comments or suggestions for the draft Technical Rationale, please provide your recommendation and explanation.

5. The SDT modified the draft Implementation Guidance for CIP-012 to provide examples of how a Responsible Entity could comply with the requirements. The draft Implementation Guidance does not prescribe the only approaches to compliance. Rather, it describes what the SDT believes would be effective ways to comply with the standard. See NERC's Compliance Guidance policy for information on Implementation Guidance. Do you agree with the draft Implementation Guidance? If you do not agree, or if you agree but have comments or suggestions for the draft Implementation Guidance, please provide your recommendation and explanation.

6. The SDT believes proposed CIP-012-1 provides entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical justification.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
FirstEnergy - FirstEnergy Corporation	Aaron Ghodooshim	3	RF	FirstEnergy Corporation	Aaron Ghdooshim	FirstEnergy - FirstEnergy Corporation	4	RF
					Aubrey Short	FirstEnergy - FirstEnergy Corporation	1	RF
					Theresa Ciancio	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Ivanc	FirstEnergy - FirstEnergy Solutions	6	RF
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC

					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
Santee Cooper	Chris Wagner	1		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Rodger Blakely	Santee Cooper	1,3,5,6	SERC
					Troy Lee	Santee Cooper	1,3,5,6	SERC
					Jennifer Richards	Santee Cooper	1,3,5,6	SERC
					Chris Jimenez	Santee Cooper	1,3,5,6	SERC
Duke Energy	Colby Bellville	1,3,5,6	FRCC,RF,SERC	Duke Energy	Doug Hils	Duke Energy	1	RF
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO

					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC
					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC

Edward Bedder	Orange & Rockland Utilities	1	NPCC
David Burke	Orange & Rockland Utilities	3	NPCC
Michele Tondalo	UI	1	NPCC
Laura Mcleod	NB Power	1	NPCC
David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
Helen Lainis	IESO	2	NPCC
Michael Schiavone	National Grid	1	NPCC
Michael Jones	National Grid	3	NPCC
Michael Forte	Con Ed - Consolidated Edison	1	NPCC
Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
Sean Cavote	PSEG	4	NPCC
Kathleen Goodman	ISO-NE	2	NPCC
Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
Quintin Lee	Eversource Energy	1	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1,5	NPCC
Salvatore Spagnolo	New York Power Authority	1	NPCC
Shivaz Chopra	New York Power Authority	6	NPCC

					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	MRO,SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	MRO
					Don Schmit	Nebraska Public Power District	5	NA - Not Applicable
					John Allen	City Utilities of Springfield, Missouri	4	MRO
					Louis Guidry	Cleco	1,3,5,6	SERC
					Robert Gray	Board of Public Utilities (Kansas City, KS) BPU	3	MRO
					Steven Keller	Southwest Power Pool Inc.	2	MRO
PPL - Louisville Gas and Electric Co.	Shelby Wade	1,3,5,6	RF,SERC	PPL NERC Registered Affiliates	Charlie Freibert	LG&E and KU Energy, LLC	3	SERC
					Brenda Truhe	PPL Electric Utilities Corporation	1	RF
					Dan Wilson	LG&E and KU Energy, LLC	5	SERC
					Linn Oelker	LG&E and KU Energy, LLC	6	SERC
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power	3	SERC

						Cooperative (Missouri)		
					Stephen Pogue	M and A Electric Power Cooperative	3	SERC
					William Price	M and A Electric Power Cooperative	1	SERC
					Jeff Neas	Sho-Me Power Electric Cooperative	3	SERC
					Peter Dawson	Sho-Me Power Electric Cooperative	1	SERC
					Mark Ramsey	N.W. Electric Power Cooperative, Inc.	1	NPCC
					John Stickley	NW Electric Power Cooperative, Inc.	3	SERC
					Ted Hilmes	KAMO Electric Cooperative	3	SERC
					Walter Kenyon	KAMO Electric Cooperative	1	SERC
					Kevin White	Northeast Missouri Electric Power Cooperative	1	SERC
					Skyler Wiegmann	Northeast Missouri Electric Power Cooperative	3	SERC
					Ryan Ziegler	Associated Electric Cooperative, Inc.	1	SERC
					Brian Ackermann	Associated Electric Cooperative, Inc.	6	SERC
					Brad Haralson	Associated Electric Cooperative, Inc.	5	SERC

1. Control Center Exemption Language: The SDT drafted Exemption language in the Applicability section specifically for CIP-012-1 to exempt Control Centers that only transmit data pertaining to a single co-located substation or generating plant. Do you agree with this revision? If not, please provide the basis for your disagreement and an alternate proposal.

Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP agrees with the principal of the exemption. However, SRP would like to see a revision of the language simplified in a fashion similar to how this question is constructed. "exempt Control Centers that only transmit data pertaining to a single-co-located substation or generation plant."	
Likes 0	
Dislikes 0	
Response	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The Technical Rationale document, in addressing this exemption, identifies the "intent" of this exemption which is to "exclude the normal RTU-style communication from a field asset about that field asset's status from CIP-012". This is commendable and the NSRF appreciates your identification of RTU-style communication as an exemption as it relates to the Control Center definition. The NSRF would like to point out that there are violations of Standards that have come down to discussions over intent. The NSRF strongly suggests that the drafting team include the Technical Rationale intent for this exemption into the actual words of the exemption to avoid future misinterpretation of the exemption. NSRF suggests the following for drafting team consideration, which also includes revisions for comments under #4 of this comment form: The NSRF recommends that the exemption reads as: A Control Center at a **BES** generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data**, such as RTU-style data,** pertaining only to the generation resource or Transmission station or substation at which the **data** transmitting **transmitted** Control Center is located. Rationale: The first use of "Control Center" implies that the exemption is for a Control Center to start with. Where it is not a Control Center but a BES facility that transmits data, via an RTU (RTU was added since it plays a pivotal point of intent within the Technical Rational document).	
Likes 0	
Dislikes 0	
Response	

Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	
The exemption language of CIP-012-1 4.2.3 refers to real-time data derived from a **single** location at a generation or Transmission station. However, the Control Center term, as defined In the Proposed Definition of Control Center, items (3) and (4), refers to "**two or more locations**" for Transmission Operators and Generator Operators. They are conflicting one another and this could lead to misinterpretation and/or misapplication of the Standard's protections. WECC believe clarity related to control Center vs. control room is necessary.	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	No
Document Name	
Comment	
Language is very confusing. Based on Idaho Power's understanding, this will eliminate smaller Control Centers but doesn't appear to have a large impact.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	No
Document Name	
Comment	
While Ameren supports the need for an Exemption for CIP-012-1, the exemption should be based on impact to reliable operations. We suggest modifying the proposed wording in 4.2.3 to provide the exemption for Low Impact Control Centers as defined in CIP-002, Attachment 1. If a Control Center regardless of its location meets the criteria for either a Medium Impact or High Impact facility then it should be protected appropriately.	
Likes 0	
Dislikes 0	

Response	
Aaron Smith - Omaha Public Power District - 1,3,5,6	
Answer	No
Document Name	
Comment	

The Technical Rationale document, in addressing this exemption, identifies the "intent" of this exemption which is to "exclude the normal RTU-style communication from a field asset about that field asset's status from CIP-012". This is commendable and the NSRF appreciates your identification of RTU-style communication as an exemption as it relates to the Control Center definition. The NSRF would like to point out that there are violations of Standards that have come down to discussion over intent; and the NSRF strongly suggests that the drafting team include the Technical Rationale intent for this exemption into the actual words of the exemption to avoid future misinterpretation of the exemption. NSRF suggests the following for drafting team consideration, which also includes revisions for comments under #4 of this comment form:

The NSRF recommends that the exemption reads as:

A Control Center at a **BES** generation resource or Transmission station or substation that transmits to a nother Control Center Real-time Assessment or Real-time monitoring

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	No
Document Name	
Comment	

Reclamation does not support an exemption. Reclamation recommends that all Real-time Assessment and Real-time monitoring data be protected against the risk of unauthorized disclosure or modification.

Instead of exempting certain Control Centers, Reclamation recommends the SDT revise the Control Center definition to give consideration to the system-wide view a Control Center has versus the limited view held by Generator Operators as follows:

One or more BES facilities, including their associated Data Centers, that monitor and control the BES and also host System Operators who:

1. perform the Real-time reliability-related tasks of a Reliability Coordinator; or
2. perform the Real-time reliability-related tasks of a Balancing Authority; or

3. perform the Real-time reliability-related tasks of a Transmission Operator for any BES Transmission Facilities; or

4. can act independently as the Generator Operator to develop specific dispatch instructions for any BES generation Facilities; or

5. can operate or direct the operation of a Transmission Owner's BES Transmission Facilities in Real-time.

Section 4.2.3, as presently written, does not clearly explain why certain Control Centers would be exempted. If an exemption is provided, Reclamation recommends the SDT incorporate language from the Technical Rationale in the exemption to avoid future confusion (i.e., Control Center implies the exemption is for a Control Center, but the data may be transmitted by a BES facility such as an RTU).

Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Ginny Beigel, City of Vero Beach, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	
Comment	

: FMPA agrees with the following comments submitted by MRO NSRF:

The Technical Rationale document, in addressing this exemption, identifies the "intent" of this exemption which is to "exclude the normal RTU-style communication from a field asset about that field asset's status from CIP-012". This is commendable and the NSRF appreciates your identification of RTU-style communication as an exemption as it relates to the Control Center definition. The NSRF would like to point out that there are violations of Standards that have come down to discussions over intent. The NSRF strongly suggests that the drafting team include the Technical Rationale intent for this exemption into the actual words of the exemption to avoid future misinterpretation of the exemption. NSRF suggests the following for drafting team consideration, which also includes revisions for comments under #4 of this comment form:

The NSRF recommends that the exemption reads as:

A Control Center at a **BES** generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data**, such as RTU-style data,** pertaining only to the generation resource or Transmission station or substation at which the **data** transmitting **transmitted** Control Center is located.

Rationale: The first use of "Control Center" implies that the exemption is for a Control Center to start with. Where it is not a Control Center but a BES facility that transmits data, via an RTU (RTU was added since it plays a pivotal point of intent within the Technical Rational document)

Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5,

1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Megan Wagner, Westar Energy, 6, 3, 1, 5; - Douglas Webb	
Answer	No
Document Name	
Comment	
Kansas City Power and Light Company incorporates the Edison Electric Institute's response to Question No. 1.	
Likes 0	
Dislikes 0	
Response	
Richard Montgomery - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	

FMPA agrees with the following comments submitted by MRO NSRF:

The Technical Rationale document, in addressing this exemption, identifies the “intent” of this exemption which is to “exclude the normal RTU-style communication from a field asset about that field asset’s status from CIP-012”. This is commendable and the NSRF appreciates your identification of RTU-style communication as an exemption as it relates to the Control Center definition. The NSRF would like to point out that there are violations of Standards that have come down to discussions over intent. The NSRF strongly suggests that the drafting team include the Technical Rationale intent for this exemption into the actual words of the exemption to avoid future misinterpretation of the exemption. NSRF suggests the following for drafting team consideration, which also includes revisions for comments under #4 of this comment form:

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Rationale: The first use of “Control Center” implies that the exemption is for a Control Center to start with. Where it is not a Control Center but a BES facility that transmits data, via an RTU (RTU was added since it plays a pivotal point of intent within the Technical Rational document)

Likes 0	
Dislikes 0	
Response	
Carol Chinn - Florida Municipal Power Agency - 3,4,5,6	
Answer	No

Document Name	

Comment

FMPA agrees with the following comments submitted by MRO NSRF:

The Technical Rationale document, in addressing this exemption, identifies the “intent” of this exemption which is to “exclude the normal RTU-style communication from a field asset about that field asset’s status from CIP-012”. This is commendable and the NSRF appreciates your identification of RTU-style communication as an exemption as it relates to the Control Center definition. The NSRF would like to point out that there are violations of Standards that have come down to discussions over intent. The NSRF strongly suggests that the drafting team include the Technical Rationale intent for this exemption into the actual words of the exemption to avoid future misinterpretation of the exemption. NSRF suggests the following for drafting team consideration, which also includes revisions for comments under #4 of this comment form:

The NSRF recommends that the exemption reads as:

A Control Center at a **BES** generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data**, such as RTU-style data,** pertaining only to the generation resource or Transmission station or substation at which the **data** transmitting **transmitted** Control Center is located.

Rationale: The first use of “Control Center” implies that the exemption is for a Control Center to start with. Where it is not a Control Center but a BES facility that transmits data, via an RTU (RTU was added since it plays a pivotal point of intent within the Technical Rational document)

Likes 0	
Dislikes 0	

Response

Joe McKinney - Florida Municipal Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

FMPA agrees with the following comments submitted by MRO NSRF:

The Technical Rationale document, in addressing this exemption, identifies the “intent” of this exemption which is to “exclude the normal RTU-style communication from a field asset about that field asset’s status from CIP-012”. This is commendable and the NSRF appreciates your identification of RTU-style communication as an exemption as it relates to the Control Center definition. The NSRF would like to point out that there are violations of Standards that have come down to discussions over intent. The NSRF strongly suggests that the drafting team include the Technical Rationale intent for this exemption into the actual words of the exemption to avoid future misinterpretation of the exemption. NSRF suggests the following for drafting team consideration, which also includes revisions for comments under #4 of this comment form:

The NSRF recommends that the exemption reads as:

A Control Center at a **BES** generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data**, such as RTU-style data,** pertaining only to the generation resource or Transmission station or substation at which the **data** transmitting **transmitted** Control Center is located.

Rationale: The first use of “Control Center” implies that the exemption is for a Control Center to start with. Where it is not a Control Center but a BES facility that transmits data, via an RTU (RTU was added since it plays a pivotal point of intent within the Technical Rational document)

Likes 0	
Dislikes 0	

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

Comments**:** FMPA agrees with the following comments submitted by MRO NSRF:

The Technical Rationale document, in addressing this exemption, identifies the “intent” of this exemption which is to “exclude the normal RTU-style communication from a field asset about that field asset’s status from CIP-012”. This is commendable and the NSRF appreciates your identification of RTU-style communication as an exemption as it relates to the Control Center definition. The NSRF would like to point out that there are violations of Standards that have come down to discussions over intent. The NSRF strongly suggests that the drafting team include the Technical Rationale intent for this exemption into the actual words of the exemption to avoid future misinterpretation of the exemption. NSRF suggests the following for drafting team consideration, which also includes revisions for comments under #4 of this comment form:

The NSRF recommends that the exemption reads as:

A Control Center at a **BES** generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data**, such as RTU-style data,** pertaining only to the generation resource or Transmission station or substation at which the **data** transmitting **transmitted** Control Center is located.

Rationale: The first use of “Control Center” implies that the exemption is for a Control Center to start with. Where it is not a Control Center but a BES facility that transmits data, via an RTU (RTU was added since it plays a pivotal point of intent within the Technical Rational document

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	No
Document Name	CIP 12 Figures.pdf

Comment

While Exelon supports the need for an Exemption for CIP-012-1, we have a concern that the language may still lack necessary clarity. For this reason, we suggest language similar to the following:

4.2.3 A generating station, Transmission station or substation that is also a Control Center, but meets one of the following criteria:

4.2.3.1 Aggregates and transmits Real-time Assessment and Real-time monitoring data from two or more Generation resource(s), Transmission station(s) and/or substation(s) but all aggregated data coming from these locations is contained within the same physical perimeter. (see Figure 1)

4.2.3.2 Does not aggregate and transmit Real-time Assessment and Real-time monitoring data from a location outside the physical perimeter where it resides. (see Figure 2)

(See CIP 12 Figures.pdf)

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

The Exemption Language is ambiguous with regard to situations where an entity could have BES assets polling Non-BES data from other locations/facilities.

Example 1: Weather Data from remote locations. No effect on generation but weather station is not physically at this facility.

Example 2: Operations of small hydro sites (under 10 mw) which are aggregated at the Low Impact BES facility but are located at other facilities.

In this example, these Low Impact Control Centers are only identified as Control Centers because they have the Capability, NOT the Responsibility, to control another Low Impact BES site. The capability is there so that technicians at one site can monitor alarms at the other Low Impact site. But these sites are not staffed around the clock, and their function is not to perform operations at the other site. We suggest a clarification on the exemption language below.

Current Language:

A Control Center at a generation resource or Transmission station or substation that transmits to another Control Center Real-time Assessment or Real-time monitoring data pertaining only to the generation resource or Transmission station or substation at which the transmitting Control Center is located.

Language Suggestion:

A Control Center at a generation resource or Transmission station or substation where all of the BES data being transmitted to another Control Center, pertains to the generation resource or Transmission station or substation at which the transmitting Control Center is located.

This language is intended to prevent small sites with Non BES data coming from other locations from being unnecessarily included in the standard.

Likes 0	
Dislikes 0	

Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
ITC is concerned with the use of Control Center in the exemption and the confusion it may cause with the originally intended definition of Control Center. ITC instead recommends the following language: Exemption: BES generation resource or Transmission station or substation that transmits Realtime monitoring or Assessment data to another Control Center, such as telemetry data, pertaining only to the generation resource or Transmission station.	
Likes 0	
Dislikes 0	
Response	
Eli Rivera - Central Electric Cooperative, Inc. (Redmond, Oregon) - NA - Not Applicable - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) agrees with Edison Electric Institute’s (EEI) comments.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to MRO NERC Standards Review Forum (NSRF) comments.	

Likes 0	
Dislikes 0	

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF, Group Name PPL NERC Registered Affiliates

Answer	No
Document Name	

Comment

Under the current definition of Control Center per the NERC Glossary of terms, what qualifies as an associated data center is unclear (e.g., associated computer room, remote computer room, distributed front-end processor).

PPL NERC Registered Affiliates requests clarification regarding treatment of aggregation of SCADA data, in particular:

- Please provide additional information and a diagram for the scope and exemptions for SCADA data from multiple substations to a remote computer room where data is aggregated at the remote computer room prior to transmitting to a data center that is associated with the Operations Center.
- Please provide additional information and a diagram regarding communications scope of CIP-012-1 (e.g. SCADA data from various substation control buildings that are at a single location and communicating back via a network used for all substation communications back to head end computer room, aggregated and then sent to Data Center).

Likes 0	
Dislikes 0	

Response

Andrea Koch - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	CIP 12 Figures.pdf

Comment

While EEI supports the need for an Exemption for CIP-012-1, we are concerned that the language may still lack necessary clarity. For this reason, we suggest language similar to the following:

4.2.3   A generating station, Transmission station or substation that is also a Control Center, but meets one of the following criteria:

4.2.3.1   Aggregates and transmits Real-time Assessment and Real-time monitoring data from two or more Generation resource(s), Transmission station(s) and/or substation(s) but all aggregated data comes from locations that are contained within the same physical perimeter. (see EEI Figure 1)

4.2.3.2 The Control Center does not aggregate and transmit Real-time Assessment and Real-time monitoring data from location(s) outside the physical perimeter where it resides. (see EEI Figure 2)

Likes 0	

Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	No
Document Name	
Comment	
Oncor supports EEI's comment.	
Likes 0	
Dislikes 0	
Response	
Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC	
Answer	No
Document Name	
Comment	
The intent of the exclusion is a positive direction, but it needs re-worded for clarity. ACES is concerned that by identifying the facility as a NERC defined, Control Center, and not a NERC defined, Facility, it will have unintended consequences of being in scope to other standards that do not directly exempt it as a Control Center. ACES would support the following modification: “A BES generation resource or Transmission station or substation that transmits Real-time Assessment or Real-time monitoring data via RTU to a Control Center, and the transmitted data pertains only to that generation resource or Transmission station or substation.”	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	No
Document Name	

Comment	
The SPP Standards Review Group has a concern that the proposed Exemption will modify the current “Control Center” definition that potentially changes how High and Low impacts assets are evaluated. The review group is proposing some language (shown below) to help maintain consistency with the “Control Center” Definition and the proposed Exemption mentioned in the documentation. Additionally, the introduction of the term “Control System” as well as the diagrams and explanations in the rationale present complexity pertaining to the current process of identifying BES Cyber Systems. We would suggest that the drafting team remove the term “Control System” from all proposed language associated with this project. Section 4.2.3. (Applicability Section –Standard) A **BES** generation resource or Transmission station or substation that transmits to a Control Center Real-time Assessment or Real-time monitoring data**, such as RTU-style data,** pertaining only to the generation resource or Transmission station or substation at which the **data transmitted** is located.	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
None.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
PacifiCorp agrees with the SDT providing the exemption language within the standard coupled with the clarification provided in the technical rationale document in the absence of revising the Control Center definition. If additional edits to the exemption language changes the scope of what is covered in the final version or is the technical rationale is not ERO-endorsed prior to the final ballot, PacifiCorp may alter its final vote. PAC understands that time and the SAR are obstacles for the SDT at this time, further development of the Control Center definition should be resolved before more standards regarding Control Centers are introduced.	
Likes 0	

Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
MEC agrees with the SDT providing the exemption language in the applicability of the standard coupled with the explanation in the technical rationale document in the absence of revising the Control Center definition. If additional edits to the exemption language changes the scope of what is covered in the final version, MEC will change its vote on the final ballot. MEC understands that time and the SAR are obstacles for the SDT at this time, however, issues with the existing Control Center definition should be resolved before more standards regarding Control Centers are introduced.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees with the SDT providing the exemption language within the standard coupled with the clarification provided in the technical rationale document in the absence of revising the Control Center definition. Please note, that NV Energy may alter its vote, If additional edits to the exemption language changes the scope of what is covered in the final version or if the technical rationale is not ERO-endorsed prior to the final ballot. NV Energy understands that a unknown expedited timeline and the original SAR are obstacles for the SDT at this time, and that this Standard will be approved in the near term, but we believe that further development of the Control Center definition should be resolved before more standards regarding Control Centers are introduced.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
What about a similar Control Center that also receives data?	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
What about a similar Control Center that also receives data?	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company supports the proposed exemption language.	
Likes 0	
Dislikes 0	
Response	
David Francis - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
Adding the wording "within the same geographical location" might help with the clarification of located	
Likes 0	
Dislikes 0	
Response	
Steve Rose - City Water, Light and Power of Springfield, IL - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Barry Lawson - National Rural Electric Cooperative Association - 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 RSC no Dominion	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Greyerbiehl - CMS Energy - Consumers Energy Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Mavis - Edison International - Southern California Edison Company - 1	
Answer	
Document Name	
Comment	
Please see comments submitted by Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	

While the SDT believes the "integrity and availability of sensitive bulk electric system data", as noted in FERC Order No. 822, paragraph 54, is addressed in R1, Texas RE notes the use of the term "or": Identification of security protection used to mitigate the risk of unauthorized disclosure *or* modification of Real-time Assessment and Real-time monitoring and control data while being transmitted between Control Centers. In its response, the SDT specifically referenced the Consideration of Issue or Directive document. In that document, the SDT makes clear that entities may elect, solely at their discretion, to protect communications links, data, or both.

Texas RE believes this directly conflicts with the plain language in FERC Order No. 822, P. 54. FERC made it clear that protections should apply to both communication links and sensitive data. However, the SDT has specified such protections could be potentially applied solely to communications links or sensitive data. That is, the SDT has endorsed permitting responsible entities to simply elect to plan and implement physical protections for communications links. This would "mitigate" the risk of an unauthorized disclosure or modification of data using one of the delineated methods. As such, the responsible entity would potentially be compliant with the standard without proposing or implementing any logical protections for sensitive data during its transmission. This appears counter to FERC's intent to protect "both the integrity and availability of sensitive bulk electric system data." FERC Order No. 822, P. 54. Texas RE maintains its recommendation to 1) change "or" to "and"; and 2) change the phrase risk of unauthorized disclosure or modification to integrity and availability of sensitive bulk electric system data.

Furthermore, Texas RE is also concerned with the SDT's shortsighted approach to securing this type of data, which permits discretion around security matters that are not in controversy and are widely considered vulnerabilities that must be mitigated. This approach is also not consistent with the "defense in depth" philosophy, which is a fundamental aspect of cyber security domains. In other words, it is a more consistent with the defense in depth concept to mitigate the risk of unauthorized disclosure and modification for this data versus one without the other.

Additionally, since GO does not appear in the definition of Control Center, Texas RE suggests removing GO from the applicability section.

Likes 0	
Dislikes 0	
Response	

2. Requirement R1: The SDT modified Requirement R1 to state: "The Responsible Entity shall implement, except under CIP Exceptional Circumstances, one or more documented plan(s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data while being transmitted between any applicable Control Centers. The Responsible Entity is not required to include oral communications in its plan." Do you agree with this revision? If not, please provide the basis for your disagreement and an alternate proposal.

Dennis Sismaet - Northern California Power Agency - 6

Answer	No
Document Name	

Comment

This is too prescriptive and unnecessary. IRO-010-2 R3.3 and TOP-003-3 R5.3 already provide reliability assurance requirements for RCs, BAs, GOs, GOPs, TOPs, TOs, and DPs. Additionally, NERC has a Standards Efficiency Initiative underway to get rid of standards and requirements such as CIP-012-1 and its' requirement 1.

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5

Answer	No
Document Name	

Comment

This is too prescriptive and unnecessary. IRO-010-2 R3.3 and TOP-003-3 R5.3 already provide reliability assurance requirements for RCs, BAs, GOs, GOPs, TOPs, TOs, and DPs. Additionally, NERC has a Standards Efficiency Initiative underway to get rid of standards and requirements such as CIP-012-1 and its' requirement 1.

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	No
Document Name	

Comment

Please refer to MRO NERC Standards Review Forum (NSRF) comments.

Likes 0	
Dislikes 0	

Response

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

: FMPA agrees with the below comments submitted by the NSRF:

The NSRF has the following three concerns and the double jeopardy of noncompliance with R1 and part 1.3.

Concern one (1); R1 states “The Responsible Entity shall implement …” where the Responsible Entity is noted within section 4.1, Functional Entities. So, each BA, GOP, GO, RC, TOP and TO shall implement a documented plan (s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessments and Real-time monitoring data. Part 1.3 states that “If the Control Centers are owned or operated by different Responsible Entities” which they will be (unless there is a vertically integrated Entity), those different Entities

already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

Concern two (2); R1.3 states “… identify the responsibilities…” this identification of responsibilities is ambiguous as each Entity can only identify their own responsibilities to “mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data…” per R1. In essence, just repeating the words within R1 is not enhancing system reliability by any means. Recommended to be removed for this concern.

Concern three (3) is similar to concern 1, where one Entity needs to identify the other Entity which will be a different entity (unless they are a vertically integrated Entity); those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

The NSRF recommends that part 1.3 be deleted in its entirety as all Functional Entities will be required to satisfy R1 and part 1.1 and 1.2.

The NSRF agrees with adding “except under CIP Exceptional Circumstances” in R1.

Likes 0	
Dislikes 0	

Response

Richard Montgomery - Florida Municipal Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment	

FMPA agrees with the below comments submitted by the NSRF:

The NSRF has the following three concerns and the double jeopardy of noncompliance with R1 and part 1.3.

Concern one (1); R1 states "The Responsible Entity shall implement …" where the Responsible Entity is noted within section 4.1, Functional Entities. So, each BA, GOP, GO, RC, TOP and TO shall implement a documented plan (s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessments and Real-time monitoring data. Part 1.3 states that "If the Control Centers are owned or operated by different Responsible Entities" which they will be (unless there is a vertically integrated Entity), those different Entities

already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

Concern two (2); R1.3 states "… identify the responsibilities…" this identification of responsibilities is ambiguous as each Entity can only identify their own responsibilities to "mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data…" per R1. In essence, just repeating the words within R1 is not enhancing system reliability by any means.   Recommended to be removed for this concern.

Concern three (3) is similar to concern 1, where one Entity needs to identify the other Entity which will be a different entity (unless they are a vertically integrated Entity); those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

The NSRF recommends that part 1.3 be deleted in its entirety as all Functional Entities will be required to satisfy R1 and part 1.1 and 1.2.

The NSRF agrees with adding "except under CIP Exceptional Circumstances" in R1.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Ginny Beigel, City of Vero Beach, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

FMPA agrees with the below comments submitted by the NSRF:

The NSRF has the following three concerns and the double jeopardy of noncompliance with R1 and part 1.3.

Concern one (1); R1 states "The Responsible Entity shall implement …" where the Responsible Entity is noted within section 4.1, Functional Entities. So, each BA, GOP, GO, RC, TOP and TO shall implement a documented plan (s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessments and Real-time monitoring data. Part 1.3 states that "If the Control Centers are owned or operated by different Responsible Entities" which they will be (unless there is a vertically integrated Entity), those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

Concern two (2); R1.3 states "… identify the responsibilities…" this identification of responsibilities is ambiguous as each Entity can only identify their own responsibilities to "mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data…" per R1. In essence, just repeating the words within R1 is not enhancing system reliability by any means. Recommended to be removed for this concern.

Concern three (3) is similar to concern 1, where one Entity needs to identify the other Entity which will be a different entity (unless they are a vertically integrated Entity); those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

The NSRF recommends that part 1.3 be deleted in its entirety as all Functional Entities will be required to satisfy R1 and part 1.1 and 1.2.

The NSRF agrees with adding "except under CIP Exceptional Circumstances" in R1

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

It is not clear how a CIP Exceptional Circumstance would impact the mitigation of the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data; therefore, Reclamation asserts that an exception for CIP Exceptional Circumstances is not necessary.

Likes 0	
Dislikes 0	

Response

Aaron Smith - Omaha Public Power District - 1,3,5,6

Answer	No
Document Name	

Comment

Comments: The NSRF has the following three concerns and the double jeopardy of noncompliance with R1 and part 1.3.

Concern one (1); R1 states "The Responsible Entity shall implement …" where the Responsible Entity is noted within section 4.1, Functional Entities. So, each BA, GOP, GO, RC, TOP and TO shall implement a documented plan (s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessments and Real-time monitoring data. Then in part 1.3 it states that "If the Control Centers are owned or operated by different Responsible Entities" which they will be (unless there is a vertically integrated Entity), those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

Concern two (2); R1.3 states "… identify the responsibilities…" this identification of responsibilities is ambiguous as each Entity can only identify their own responsibilities to "mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data…" per R1. In essence, just repeating the words within R1 is not enhancing system reliability by any means. Recommended to be removed for this concern.

Concern three (3) is similar to concern 1, where one Entity needs to identify the other Entity which will be a different entity (unless they are a vertically integrated Entity); those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

The NSRF recommends that part 1.3 be deleted in its entirety as all Functional Entities will be required to satisfy R1 and part 1.1 and 1.2.

The NSRF agrees with adding "except under CIP Exceptional Circumstances" in R1.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The NSRF has the following three concerns and the double jeopardy of noncompliance with R1 and part 1.3.

Concern one (1); R1 states "The Responsible Entity shall implement …" where the Responsible Entity is noted within section 4.1, Functional Entities. So, each BA, GOP, GO, RC, TOP and TO shall implement a documented plan (s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessments and Real-time monitoring data. Part 1.3 states that "If the Control Centers are owned or operated by different Responsible Entities" which they will be (unless there is a vertically integrated Entity), those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

Concern two (2); R1.3 states "… identify the responsibilities…" this identification of responsibilities is ambiguous as each Entity can only identify their own responsibilities to "mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data…" per R1. In essence, just repeating the words within R1 is not enhancing system reliability by any means. Recommended to be removed for this concern.

Concern three (3) is similar to concern 1, where one Entity needs to identify the other Entity which will be a different entity (unless they are a vertically integrated Entity); those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

The NSRF recommends that part 1.3 be deleted in its entirety as all Functional Entities will be required to satisfy R1 and part 1.1 and 1.2.

The NSRF agrees with adding "except under CIP Exceptional Circumstances" in R1.

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
The SPP Standards Review Group has no issues with the language proposed, however, we would recommend that the SDT include an example pertaining to the under CIP Exceptional Circumstances in the Implementation Guidance Document.	
Likes 0	
Dislikes 0	
Response	
David Francis - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	
Adding that statement clarifies the excludes meaning	
Likes 0	
Dislikes 0	
Response	
Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC	
Answer	Yes
Document Name	
Comment	
ACES supports the modified R1.	
Likes 0	
Dislikes 0	

Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Oncor supports EEI's comment.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the proposed revisions.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Andrea Koch - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the Requirement 1 revisions. EEI also supports the flexibility provided by Requirement 1; however, there are many different approaches to mitigating the risk of unauthorized disclosure or modification of data in transit. Additional guidance that explores various approaches and evaluates their effectiveness in mitigating risk may be helpful before entities make implementation investments for CIP-012-1.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Is <<Real-time monitoring data>> the same as operational data? Operational data is in other Standards	
Likes 0	
Dislikes 0	
Response	

Eli Rivera - Central Electric Cooperative, Inc. (Redmond, Oregon) - NA - Not Applicable - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (“CenterPoint Energy”) agrees with Edison Electric Institute’s (EEI) comments.	
Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	

Answer	Yes
Document Name	
Comment	
Duke Energy agrees with the proposed revision.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the Requirement 1 revisions. Exelon also supports the flexibility provided by Requirement 1; however, there are many different approaches to mitigating the risk of unauthorized disclosure or modification of data in transit. Additional guidance that explores various approaches and evaluates their effectiveness in mitigating risk may be helpful before entities make implementation investments for CIP-012-1.	
Likes 0	
Dislikes 0	
Response	
Barry Lawson - National Rural Electric Cooperative Association - 4	
Answer	Yes
Document Name	
Comment	
NRECA supports the modified R1; however, we request that the SDT provide clarification on why R1.3 is needed, especially when R1, R1.1 and R1.2 seem to have an overlap in what is required with R1.3. With a clarification on the need for R1.3, NRECA believes that will help registered entities to better understand why R1.3 is necessary. With this clarification, it may not be necessary to remove R1.3.	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	

NV Energy agrees with the requirement based on the newly introduced paragraph in the Implementation Guidance, “Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP.”

NV Energy would like the following edit added “or where other physical protections are applied.” NV Energy believes that this will allow entities flexibility where their devices that perform this function are located within its location. NV Energy believes the VPN examples provided are necessary and should remain within the Guidance document. If the newly introduced paragraph or the VPN example are removed or if the implementation guidance is not ERO-endorsed prior to the final ballot, NV Energy may alter its final vote.

Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham

Answer	Yes
Document Name	
Comment	

MEC agrees with the requirement based on the newly introduced sentence in the Implementation Guidance, “Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP.” MEC would like the following edit added “or where other physical protections are applied.” This will provide more flexibility for entities. MEC also likes the VPN example provided. Inclusion of the newly introduced sentence, the VPN example and ERO-endorsement of the implementation guidance are needed in the final version for MEC to vote yes on the final ballot.

Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	Yes
Document Name	
Comment	

PacifiCorp agrees with the requirement based on the newly introduced paragraph in the Implementation Guidance, “Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP.” PacifiCorp would like the following edit added “or where other physical protections are applied.” PacifiCorp feels that this will allow entities flexibility where the devices that perform this are located within its location. PacifiCorp also likes the VPN examples provided. If the newly introduced paragraph or the VPN example are removed or if the implementation guidance is not ERO-endorsed prior to the final ballot, PacifiCorp may alter its final vote.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	

Comment

It is always good to include exceptions for unforeseen circumstances and emergencies.

Likes 0	
Dislikes 0	

Response

Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI

Answer	Yes
Document Name	

Comment

AECI and members of the AECI group are supportive of the comments provided by NRECA.

Likes 0	
Dislikes 0	

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer	Yes
Document Name	

Comment	
SRP agrees the data should be protected. SRP also agrees the protections for the data in scope must ensure the data has not been modified, and that FERC directed NERC to “specify how the confidentiality, integrity, and availability of each type of bulk electric system data should be protected while it is being transmitted.” However, SRP takes exception to the extent the proposed standard requires the data in scope to be protected. FERC Order 822 states on page 36, “…we recognize that not all communication network components and data pose the same risk to bulk electric system reliability and may not require the same level of protection.” However, the proposed standard applies the same criteria of protection against unauthorized disclosure across all of the data within the defined scope. SRP does not agree viewing of the Real-time Assessment and Real-time monitoring and control data without context will decrease the reliable operation of the BES and asserts confidentiality does not need to be protected for all data under this scope. Along with this, SRP would like a clarification of how the SDT defines Real-Time Assessment Data. Additionally, SRP recognizes the SDT is not specifying the controls used to protect confidentiality and integrity. However, the only method available to achieve the proposed required objective is to implement encryption. FERC Order 822 states on page 39, “it is reasonable to conclude that any lag in communication speed resulting from implementation of protections [encryption technologies] should only be measureable on the order of milliseconds and, therefore, will not adversely impact Control Center communications,” but SRP asserts this statement only refers to a single data stream. It is unknown what encryption will do when dealing with multiple data streams being transmitted at once, from one to many points, not only to the latency added for the reliable operation of the BES, but also to the computing resources	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
David Greyerbiehl - CMS Energy - Consumers Energy Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Megan Wagner, Westar Energy, 6, 3, 1, 5; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rose - City Water, Light and Power of Springfield, IL - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	

Response	
Joe McKinney - Florida Municipal Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	

: FMPA agrees with the below comments submitted by the NSRF:

The NSRF has the following three concerns and the double jeopardy of noncompliance with R1 and part 1.3.

Concern one (1); R1 states "The Responsible Entity shall implement …" where the Responsible Entity is noted within section 4.1, Functional Entities. So, each BA, GOP, GO, RC, TOP and TO shall implement a documented plan (s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessments and Real-time monitoring data. Part 1.3 states that "If the Control Centers are owned or operated by different Responsible Entities" which they will be (unless there is a vertically integrated Entity), those different Entities

already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

Concern two (2); R1.3 states "… identify the responsibilities…" this identification of responsibilities is ambiguous as each Entity can only identify their own responsibilities to "mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data…" per R1. In essence, just repeating the words within R1 is not enhancing system reliability by any means. Recommended to be removed for this concern.

Concern three (3) is similar to concern 1, where one Entity needs to identify the other Entity which will be a different entity (unless they are a vertically integrated Entity); those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

The NSRF recommends that part 1.3 be deleted in its entirety as all Functional Entities will be required to satisfy R1 and part 1.1 and 1.2.

The NSRF agrees with adding "except under CIP Exceptional Circumstances" in R1.

Likes 0	

Dislikes 0	
Response	
Carol Chinn - Florida Municipal Power Agency - 3,4,5,6	
Answer	
Document Name	
Comment	

: FMPA agrees with the below comments submitted by the NSRF:

The NSRF has the following three concerns and the double jeopardy of noncompliance with R1 and part 1.3.

Concern one (1); R1 states “The Responsible Entity shall implement …” where the Responsible Entity is noted within section 4.1, Functional Entities. So, each BA, GOP, GO, RC, TOP and TO shall implement a documented plan (s) to mitigate the risk of unauthorized disclosure or modification of Real-time Assessments and Real-time monitoring data. Part 1.3 states that “If the Control Centers are owned or operated by different Responsible Entities” which they will be (unless there is a vertically integrated Entity), those different Entities

already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

Concern two (2); R1.3 states “… identify the responsibilities…” this identification of responsibilities is ambiguous as each Entity can only identify their own responsibilities to “mitigate the risk of unauthorized disclosure or modification of Real-time Assessment and Real-time monitoring data…” per R1. In essence, just repeating the words within R1 is not enhancing system reliability by any means. Recommended to be removed for this concern.

Concern three (3) is similar to concern 1, where one Entity needs to identify the other Entity which will be a different entity (unless they are a vertically integrated Entity); those different Entities already need to satisfy R1 since they are in section 4.1. This part 1.3 is redundant and is recommended to be removed.

The NSRF recommends that part 1.3 be deleted in its entirety as all Functional Entities will be required to satisfy R1 and part 1.1 and 1.2.

The NSRF agrees with adding “except under CIP Exceptional Circumstances” in R1.

Likes 0	
Dislikes 0	
Response	

3. Implementation Plan: The SDT established the Implementation Plan to make the standard effective the first day of the first calendar quarter that is twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard, or as otherwise provided for by the applicable governmental authority. Do you agree with this proposal? If you think an alternate implementation time period is needed, please provide a detailed explanation of actions and time needed to meet the implementation deadline.

Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	

Overall, SRP does not agree with twenty-four (24) calendar months for the implementation of Requirements R1, as R1 and R2 from the second draft have been merged. Although SRP recognizes the SDT is not specifying the controls to be used to protect confidentiality and integrity, the only examples provided in the implementation guidance includes encryption. If there are other methods available to achieve the security objective, SRP asks the SDT to provide them. However, the only method available to achieve the proposed required objective, on the ICCP network, is to implement encryption. As FERC order 822 states on page 37, "if several registered entities have joint responsibility for a cryptographic key management system used between their respective Control Centers, they should have the prerogative to come to a consensus on which organization administers that particular key management system." Furthermore, the FERC order states on page 38, "While responsible entities are required to exchange real-time and operational planning data necessary to operate the bulk electric system using mutually agreeable security protocols, there is no technical specification for how this transfer of information should incorporate mandatory security controls." These are activities and specifications that must be created and agreed upon by all registered entities involved in the data transfer. As such the timeline is reliant on registered entities working together on a common solution and would not be achievable within 24 calendar months.

Additionally, if encryption fails, SRP would lose Real-time Assessment and Real-time monitoring and control data. There are many opportunities for encryption to fail that must be addressed. The implementation of encryption requires a pilot to truly understand and address the mechanisms of failure, the impacts encryption would cause on the exchange of the data, and the computing resources required. A pilot also requires a great amount of coordination to execute, not only within the industry, but may also include carriers, vendors, and possibly third-party encryption key program managers.

Because of the aforementioned reasons and concerns, SRP is recommending a phased implementation for CIP-012-1. A 24 month implementation is appropriate, but only for Requirement R1. The 24 months for R1 would provide time to coordinate and create an industry-wide solution. SRP is proposing the SDT include an additional 12 months for the plan implementation aspect of Requirement R1. The additional 12 months would be used for a pilot and course correction if needed, in addition to understanding, formulating, and executing maintenance strategies.

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	

WECC believes the Implementation Plan of 24 months is unnecessary and the standard 18-month Implementation Plan should suffice. However, if the clarification sought in question 1 above is provided, WECC would not vote NO solely based on the length of the Implementation Plan.

Likes 0	
Dislikes 0	

Response

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy disagrees that twenty-four calendar (24) months is enough time for implementation. We reiterate our previous comment and suggest a staggered implementation plan for CIP-012 specifically concerning coordination with neighboring entities. We consider it possible for an entity to gather necessary data, convening of internal work groups, and drafting of security protection plans in the proposed 24 month Implementation Plan. However, we feel that the coordination with other entities that will be necessary for R1.3 will take longer than the proposed 24 months, especially with internal work already taking place. We recommend the drafting team consider a staggered implementation plan for internal work (18 months) compared to external coordination work (36 months). When considering coordination/testing with neighboring entities, possible equipment upgrades/lead times that could ensue, we feel that additional time above the proposed 24-month Implementation Plan is warranted.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA agrees with the intent of the FERC Directive. BPA is concerned about the proposed solution and its implementation timeline.

BPA requests that the SDT incorporate a pilot project to validate the proposed solution; is designed to address the FERC directive. Additionally, BPA requests the implementation timeframe to be extended to a 36 month phased implementation timeline; to begin upon successful completion of the pilot project. The industry needs 36 months due to the large amount of applicable data, access to funds, budget cycle, and resources to perform work required.

BPA is concerned about 3rd party encryption keys and the risks they pose, including the expiration of encryption keys. When an encryption key expires, the data flow ceases immediately to include Real-time Assessment and Real-time monitoring and control data. BPA requests that controls be put in place to ensure mitigation measures do not allow encryption keys to expire. Additionally, BPA is concerned that there is a risk of the certificate authority being unavailable for authentication, impacting maintenance of reliable communications between control centers for operation of the Bulk Electric System.

BPA also agrees with SRP comments, as follows:

“Overall, SRP does not agree with twenty-four (24) calendar months for the implementation of Requirements R1, as R1 and R2 from the second draft have been merged. Although SRP recognizes the SDT is not specifying the controls to be used to protect confidentiality and integrity, the only examples provided in the implementation guidance includes encryption. If there are other methods available to achieve the security objective, SRP asks the SDT to provide them. However, the only method available to achieve the proposed required objective, on the ICCP network, is to implement encryption. As FERC order 822 states on page 37, “if several registered entities have joint responsibility for a cryptographic key management system used between their respective Control Centers, they should have the prerogative to come to a consensus on which organization administers that particular key management system.” Furthermore, the FERC order states on page 38, “While responsible entities are required to exchange real-time and operational planning data necessary to operate the bulk electric system using mutually agreeable security protocols, there is no technical specification for how this transfer of information should incorporate mandatory security controls.” These are activities and specifications that must be created and agreed upon by all registered entities involved in the data transfer. As such the timeline is reliant on registered entities working together on a common solution and would not be achievable within 24 calendar months.

Additionally, if encryption fails, SRP would lose Real-time Assessment and Real-time monitoring and control data. There are many opportunities for encryption to fail that must be addressed. The implementation of encryption requires a pilot to truly understand and address the mechanisms of failure, the impacts encryption would cause on the exchange of the data, and the computing resources required. A pilot also requires a great amount of coordination to execute, not only within the industry, but may also include carriers, vendors, and possibly third-party encryption key program managers.

Because of the aforementioned reasons and concerns, SRP is recommending a phased implementation for CIP-012-1. A 24 month implementation is appropriate, but only for Requirement R1. The 24 months for R1 would provide time to coordinate and create an industry-wide solution. SRP is proposing the SDT include an additional 12 months for the plan implementation aspect of Requirement R1. The additional 12 months would be used for a pilot and course correction if needed, in addition to understanding, formulating, and executing maintenance strategies.”

Likes 0	
Dislikes 0	

Response

Marty Hostler - Northern California Power Agency - 5

Answer	No
Document Name	

Comment

No, this standard should never be implemented! This is too prescriptive and unnecessary. IRO-010-2 R3.3 and TOP-003-3 R5.3 already provide reliability assurance requirements for RCs, BAs, GOs, GOPs, TOPs, TOs, and DPs. Additionally, NERC has a Standards Efficiency Initiative underway to get rid of standards and requirements such as CIP-012-1 and its' requirement 1.

Likes 0	
Dislikes 0	

Response

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
No, this standard should never be implemented! This is too prescriptive and unnecessary. IRO-010-2 Question 3	
Likes 0	
Dislikes 0	
Response	
Joe McKinney - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	

None	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
The implementation plan is agreeable for a new CIP requirement to provide ample time to evaluate the impact and prepare the appropriate controls and procedures.	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 1,3,6	
Answer	Yes
Document Name	
Comment	
Ameren supports the proposed twenty-four (24) month implementation plan due to the complexity of securing control center to control center communications, which will require significant external coordination, procurement and installation of new technology and processes, legal reviews, and training. Technical challenges to implementing the standard will also be significant. For example, entities may deploy Secure ICCP as their CIP-012-1 solution. The Pacific Northwest National Laboratory's ("PNNL") June 2017 report, "Secure ICCP," identifies technical and other challenges for entities implementing secure ICCP (e.g., limited industry experience, documentation, support, difficulties with software upgrades and patching). The PNNL report is available at: https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-26729.pdf. While these issues are not insurmountable they will take time, and should not be inappropriately rushed.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
With any Standard that provides multiple iterations for proving compliance, a longer timeline is necessary, and we support a 24 month window for implementation.	
Likes 0	
Dislikes 0	
Response	

Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the proposed twenty-four (24) month implementation plan due to the complexity of securing control center to control center communications, which will require significant external coordination, procurement and installation of new technology and processes, legal reviews, and training.	
Likes 0	
Dislikes 0	
Response	

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Considering the complexity, it is estimated that 36 calendar months would be required to comply.	
Likes 0	
Dislikes 0	
Response	
Andrea Koch - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the proposed twenty-four (24) month implementation plan due to the complexity of securing control center to control center communications, which will require significant external coordination, procurement and installation of new technology and processes, legal reviews, and training. Technical challenges to implementing the standard will also be significant. For example, entities may deploy Secure ICCP as their CIP-012-1 solution. The Pacific Northwest National Laboratory's ("PNNL") June 2017 report, "Secure ICCP," identifies technical and other challenges for entities implementing secure ICCP (e.g., limited industry experience, documentation, limited user community, support, difficulties with software upgrades and patching). The report details the implementation of Secure ICCP using the same EMS vendor software. Similar installations using different or comingled EMS vendor software may prove to be even more challenging. The PNNL report is available at: https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-26729.pdf. In order to ensure there is sufficient time to address such reliability and compliance issues, EEI supports NERC's proposed twenty-four (24) month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	

Southern Company supports the proposed twenty-four (24) month implementation plan.

Likes 0	
Dislikes 0	

Response

Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Oncor supports EEI's comment.	
Likes 0	
Dislikes 0	
Response	

Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC	
Answer	Yes
Document Name	
Comment	
:ACES believes that twenty-four (24) calendar months after the effective date of the applicable governmental authority's order approving the standard for implementation is appropriate.	
Likes 0	
Dislikes 0	
Response	

David Francis - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	

However, because this may invovle third parites equiement being place or added to a PSP based on the Technical Rationale and Justification for Reliability Standard guidance may need extended design and implementation efforts in meeting the PSP security requirments	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
While it will take less time for entities to implement intra-entity solutions, it will take time for inter-entity solutions to be drafted and agreed upon. Since both entities will need to agree on not just implementing a technical solution (e.g. IPSec, Secure ICCP), but how to maintain it (e.g. cryptography key management).	
Likes 0	
Dislikes 0	
Response	
Steve Rose - City Water, Light and Power of Springfield, IL - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Smith - Omaha Public Power District - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Ginny Beigel, City of Vero Beach, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Megan Wagner, Westar Energy, 6, 3, 1, 5; - Douglas Webb	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Richard Montgomery - Florida Municipal Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Carol Chinn - Florida Municipal Power Agency - 3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Barry Lawson - National Rural Electric Cooperative Association - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eli Rivera - Central Electric Cooperative, Inc. (Redmond, Oregon) - NA - Not Applicable - Texas RE	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Greyerbiehl - CMS Energy - Consumers Energy Company - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Technical Rationale: The SDT modified the draft Technical Rationale for CIP-012 to further explain the need for the exemption for certain Control Centers. Do you agree with the explanations and included diagrams in the draft Technical Rationale? If you do not agree, or if you agree but have comments or suggestions for the draft Technical Rationale, please provide your recommendation and explanation.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group

Answer	No
Document Name	

Comment

The SPP Standards Review Group has a concern that the proposed Exemption will modify the current “Control Center” definition that potentially changes how High and Low impacts assets are evaluated. The review group is proposing some language (shown below) to help maintain consistency with the “Control Center” Definition and the proposed Exemption mentioned in the documentation. Additionally, the introduction of the term “Control System” as well as the diagrams and explanations in the rationale present complexity pertaining to the current process of identifying BES Cyber Systems. We would suggest that the drafting team remove the term “Control System” from all proposed language associated with this project.

Section 4.2.3. (Applicability Section –Standard)

A **BES** generation resource or Transmission station or substation that transmits to a Control Center Real-time Assessment or Real-time monitoring data**, such as RTU-style data,** pertaining only to the generation resource or Transmission station or substation at which the **data transmitted** is located.

Likes 0	
Dislikes 0	

Response

David Francis - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF

Answer	No
Document Name	

Comment

Increases security risk with repair personnel going into a PSP without knowning all the CIP security requirments for such devises and have in house personnel escorting the repair personnel during any repair work

Likes 0	
Dislikes 0	

Response

David Greyerbiehl - CMS Energy - Consumers Energy Company - 5

Answer	No

Document Name	
Comment	
In the Technical Rationale document, please specify what type of date under TOP-003 and IRO-010 should be excluded from the CIP-012 requirements.	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	
Comment	
In the Technical Rationale document, please specify what type of date under TOP-003 and IRO-010 should be excluded from the CIP-012 requirements.	
Likes 0	
Dislikes 0	
Response	
Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to MRO NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No

Document Name	
Comment	

The technical rational should show examples of demarcation points for the protections or define the demarcation points. For example, if a leased line or router is not owned by the entity, however the entity chose to deploy a firewall to encrypt the traffic ahead of the router, then the firewall shall be the demarcation point, not the router. Explanations left to the entity without proper guidance may lead to confusion. Furthermore, while entities may not own both sides of the links, technologies such as VPN require both sides to follow the same configuration in order to encrypt data. If the other side is not equipped to encrypt the data, the link will remain unsecure.

Likes 0	
Dislikes 0	
Response	

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	
Comment	

Duke Energy suggests the drafting team consider adding a diagram that demonstrates under what circumstances a generating resource or Transmission sub would be applicable to this standard. With the added exemption language, it would be helpful for the industry to have a couple of examples where the exemption would not apply to existing generation resources and Transmission subs.

Likes 0	
Dislikes 0	
Response	

Chris Gowder - Florida Municipal Power Agency - 3,4,5,6

Answer	No
Document Name	
Comment	

FMPA agrees with the following comments submitted by the NSRF:

The NSRF does not agree that Figure 2 and related discussion within the Technical Rationale document applies to Transmission stations and substations and generation resources as being “Control Centers”. The NSRF believes that the Control Center definition was developed with the intent to apply to functionally manned control centers that monitor and control the BES; a center that hosts System Operators that have specific training requirements and in some instances certifications to meet the requirements of their position. It appears the drafting team is expanding the Control Center definition for a field asset application in order to meet the needs of an exemption for CIP-012. Consider also, that in the last sentence of the first paragraph of the Reference Model Discussion in the Implementation Guidance it correctly states “Additionally, Entity Alpha does not need to consider any communications to other non-Control Center facilities such as generating plants or substations. These communications are out of scope for CIP-012-1” [emphasis added] The NSRF does agree that RTU-style data transmission between BES generation and Transmission stations and substations

need to be explicitly excluded from CIP-012. The NSRF, under Comment #1 on this form, has provided revision language that meets our comments here and those already addressed

Likes 0	
Dislikes 0	

Response

Joe McKinney - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	

Comment
FMPA agrees with the following comments submitted by the NSRF: The NSRF does not agree that Figure 2 and related discussion within the Technical Rationale document applies to Transmission stations and substations and generation resources as being "Control Centers". The NSRF believes that the Control Center definition was developed with the intent to apply to functionally manned control centers that monitor and control the BES; a center that hosts System Operators that have specific training requirements and in some instances certifications to meet the requirements of their position. It appears the drafting team is expanding the Control Center definition for a field asset application in order to meet the needs of an exemption for CIP-012. Consider also, that in the last sentence of the first paragraph of the Reference Model Discussion in the Implementation Guidance it correctly states "Additionally, Entity Alpha does not need to consider any communications to other non-Control Center facilities such as generating plants or substations. These communications are out of scope for CIP-012-1" [emphasis added].

Likes 0	
Dislikes 0	

Response

Carol Chinn - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	

Comment
FMPA agrees with the following comments submitted by the NSRF: The NSRF does not agree that Figure 2 and related discussion within the Technical Rationale document applies to Transmission stations and substations and generation resources as being "Control Centers". The NSRF believes that the Control Center definition was developed with the intent to apply to functionally manned control centers that monitor and control the BES; a center that hosts System Operators that have specific training requirements and in some instances certifications to meet the requirements of their position. It appears the drafting team is expanding the Control Center definition for a field asset application in order to meet the needs of an exemption for CIP-012. Consider also, that in the last sentence of the first paragraph of the Reference Model Discussion in the Implementation Guidance it correctly states "Additionally, Entity Alpha does not need to consider

any communications to other non-Control Center facilities such as generating plants or substations. These communications are out of scope for CIP-012-1” [emphasis added].

Likes 0	
Dislikes 0	

Response

Richard Montgomery - Florida Municipal Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

FMPA agrees with the following comments submitted by the NSRF:

The NSRF does not agree that Figure 2 and related discussion within the Technical Rationale document applies to Transmission stations and substations and generation resources as being “Control Centers”. The NSRF believes that the Control Center definition was developed with the intent to apply to functionally manned control centers that monitor and control the BES; a center that hosts System Operators that have specific training requirements and in some instances certifications to meet the requirements of their position. It appears the drafting team is expanding the Control Center definition for a field asset application in order to meet the needs of an exemption for CIP-012. Consider also, that in the last sentence of the first paragraph of the Reference Model Discussion in the Implementation Guidance it correctly states “Additionally, Entity Alpha does not need to consider any communications to other non-Control Center facilities such as generating plants or substations. These communications are out of scope for CIP-012-1” [emphasis added].

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Ginny Beigel, City of Vero Beach, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

Comments: FMPA agrees with the following comments submitted by the NSRF:

The NSRF does not agree that Figure 2 and related discussion within the Technical Rationale document applies to Transmission stations and substations and generation resources as being “Control Centers”. The NSRF believes that the Control Center definition was developed with the intent to apply to functionally manned control centers that monitor and control the BES; a center that hosts System Operators that have specific training requirements and in some instances certifications to meet the requirements of their position. It appears the drafting team is expanding the Control Center definition for a field asset application in order to meet the needs of an exemption for CIP-012. Consider also, that in the last sentence of the first paragraph of the Reference Model Discussion in the Implementation Guidance it correctly states “Additionally, Entity Alpha does not need to consider any communications to other non-Control Center facilities such as generating plants or substations. These communications are out of scope for CIP-012-1" [emphasis added].

The NSRF does agree that RTU-style data transmission between BES generation and Transmission stations and substations need to be explicitly excluded from CIP-012. The NSRF, under Comment #1 on this form, has provided revision language that meets our comments here and those already addressed

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer	No
Document Name	

Comment

In the Technical Rationale document, please specify what type of date under TOP-003 and IRO-010 should be excluded from the CIP-012 requirements.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Reclamation recommends that all Real-time Assessment and Real-time monitoring data be protected against the risk of unauthorized disclosure or modification. Reclamation asserts that the need to protect the data from a GOP Control Center with the ability to control more than two geographically separated facilities is no different than the need to protect the data from each single location, and no different from the need to protect data from a GOP Control Center to an RC or BA Control Center.

Likes 0	
Dislikes 0	

Response

Aaron Smith - Omaha Public Power District - 1,3,5,6

Answer	No
Document Name	

Comment

The NSRF does not agree that Figure 2 and related discussion within the Technical Rationale document applies to Transmission stations and substations and generation resources as being “Control Centers”. The NSRF believes that the Control Center definition was developed with the intent to apply to functionally manned control centers that monitor and control the BES; a center that hosts System Operators that have specific training requirements and in some instances certifications to meet the requirements of their position. It appears the drafting team is expanding the Control Center definition for a field asset application in order to meet the needs of an exemption for CIP-012. Consider also, that in the last sentence of the first paragraph of the Reference Model Discussion in the Implementation Guidance it correctly states “Additionally, Entity Alpha does not need to consider any communications to other non-Control Center facilities such as generating plants or substations. These communications are out of scope for CIP-012-1” [emphasis added].

The NSRF does agree that RTU-style data transmission between BES generation and Transmission stations and substations need to be explicitly excluded from CIP-012. The NSRF, under Comment #1 on this form, has provided revision language that meets our comments here and those already addressed.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6

Answer	No
Document Name	

Comment

We believe that any of the technical rationale that can be condensed into clear, concise language should be moved into the CIP-012-1 as a defined requirement. Responsible Entities are audited to the Requirements in the Standard. Leaving this much information as Technical Rationale invites subjective audit interpretation unnecessarily increases compliance risk for the entity.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

Idaho Power believes Figures 2 & 3 start to muddy the waters a little bit in terms of the initial intent of the CIP-012. Figure 2 seems to state that Station Alpha would be considered a control center, but Figure 3 seems to state that the communication between Station Alpha and the TOP control center would not be in scope of CIP-012. While Idaho Power would agree that in the end that seems to get to of the objective of the initial intent of CIP-012, this seems like a confusing way to reach that conclusion.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The NSRF does not agree that Figure 2 and related discussion within the Technical Rationale document applies to Transmission stations and substations and generation resources as being “Control Centers”. The NSRF believes that the Control Center definition was developed with the intent to apply to functionally manned control centers that monitor and control the BES; a center that hosts System Operators that have specific training requirements and in some instances certifications to meet the requirements of their position. It appears the drafting team is expanding the Control Center definition for a field asset application in order to meet the needs of an exemption for CIP-012. Consider also, that in the last sentence of the first paragraph of the Reference Model Discussion in the Implementation Guidance it correctly states “Additionally, Entity Alpha does not need to consider any communications to other non-Control Center facilities such as generating plants or substations. These communications are out of scope for CIP-012-1” [emphasis added].

The NSRF does agree that RTU-style data transmission between BES generation and Transmission stations and substations need to be explicitly excluded from CIP-012. The NSRF, under Comment #1 on this form, has provided revision language that meets our comments here and those already addressed.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP requests the SDT consider including some statements in the Technical Rationale to address the possibility that data requests made related to TOP-003 and/or IRO-010 include other data that is not Real-time Assessment data or Real-time monitoring data, and how the Responsible Entity could exclude this other data from the security requirements.

The following text on page vi may need to be edited for sake of clarity “The only thing that has changed is an HMI for Station Beta has been moved within close physical proximity to an HMI for Station Alpha.”

Likes 0	
Dislikes 0	

Response

Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 3

Answer	Yes
Document Name	

Comment

PNM Resources supports EEI’s comments on this question.

Likes 0	
Dislikes 0	

Response

Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC

Answer	Yes
Document Name	

Comment

No comments.

Likes 0	
Dislikes 0	

Response

Quintin Lee - Eversource Energy - 1

Answer	Yes
Document Name	

Comment

We feel that the example presented in the Technical Guidance reflects the Exemption accurately, however, the SDT is compounding the Control Center issue by having another explanation of a Control Center/control center to those already present in CIP-002, CIP-014, and the NERC Glossary, and now CIP-012. We recommend a single document that explains the Control Center / control center topic.	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	Yes
Document Name	
Comment	
Oncor supports EEI's comment.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Southern Company supports the need to exempt certain Control Centers. Barring the ability to address the Control Center definition fully, Southern recognizes that the proposed Standard addresses the need for an exemption in an appropriate way.	
Likes 0	
Dislikes 0	
Response	
Andrea Koch - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	CIP 12 Figures.pdf
Comment	

EEI supports the need for an exemption and explanation for digital control systems installed at generating stations and Transmission stations and substations that may also be classified as Control Centers. However, we have concerns that some parts of the Technical Rationale may align too closely with NERC's description of Implementation Guidance. (see Technical Rationale Transition Plan) In the redline edits provided by the SDT, Figures 2 and 3 provide examples of communications between two generating stations, while technically conforming to the definition of a Control Center, are outside the intended scope of CIP-012-1 standard. While the language and figures provide needed clarity, we suggest the SDT consider using diagrams that more closely conforms to the figures provided within our comments. We have provided these suggested changes because we are concerned that the issues of aggregated communications along with situations where Facilities contained within a single confined area are not clearly addressed in the Technical Rationale. We believe the diagrams provided more clearly define the limitations of the exemption. As stated above, we are concerned that the examples and approaches provided in the Technical Rationale may be better contained in the Implementation Guidance given the above referenced NERC document suggests that Implementation Guidance is where examples and approaches are to be used to illustrate how to comply with a Reliability Standard.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion	
Answer	Yes
Document Name	
Comment	
We feel that the example presented in the Technical Guidance reflects the Exemption accurately, however, the SDT is compounding the Control Center issue by having another explanation of a Control Center/control center to those already present in CIP-002, CIP-014, and the NERC Glossary, and now CIP-012. We recommend a single document that explains the Control Center / control center topic.	
Likes 0	
Dislikes 0	
Response	

Eli Rivera - Central Electric Cooperative, Inc. (Redmond, Oregon) - NA - Not Applicable - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") agrees with Edison Electric Institute's (EEI) comments.	
Likes 0	

Dislikes 0	

Response

Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	

Comment

Exelon supports the need for an exemption and explanation for digital control systems installed at generating stations and Transmission stations and substations that may also be classified as Control Centers. However, we have concerns that some parts of the Technical Rationale may align too closely with NERC's description of Implementation Guidance. (see Technical Rationale Transition Plan)

In the redline edits provided by the SDT, Figures 2 and 3 provide examples of communications between two generating stations, while technically conforming to the definition of a Control Center, are outside the intended scope of CIP-012-1 standard. While the language and figures provide needed clarity, we suggest the SDT consider using diagrams that more closely conform to the figures provided within our comments. We have provided these suggested changes because we are concerned that the issues of aggregated communications along with situations where Facilities contained within a single confined area are not clearly addressed in the Technical Rationale. We believe the diagrams provided more clearly define the limitations of the exemption.

Exelon is also concerned that the examples and approaches provided in the Technical Rationale may be better contained in the Implementation Guidance given the above referenced NERC document suggests that Implementation Guidance is where examples and approaches are to be used to illustrate how to comply with a Reliability Standard.

Likes 0	
Dislikes 0	

Response

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	

Comment

NV Energy understands that a unknown expedited timeline and the original SAR are obstacles for the SDT at this time, and that this Standard will be approved in the near term, but we believe that further development of the Control Center definition should be resolved before more standards regarding Control Centers are introduced.

Likes 0	
Dislikes 0	

Response

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
While MEC understands that time and the SAR are obstacles for the SDT at this time, however, issues with the existing Control Center definition should be resolved before more standards regarding Control Centers are introduced.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
PAC understands that time and the SAR are obstacles for the SDT at this time, further development of the Control Center definition should be resolved before more standards regarding Control Centers are introduced.	
Likes 0	
Dislikes 0	
Response	
Russell Martin II - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
SRP agrees with the Technical Rationale and Justification for CIP-012 provided by the SDT. However, SRP continues to maintain that an additional 12 months be considered for the plan implementation aspect of Requirement R1. PDF page 6, paragraph 3 of section title *Identification of Where Security Protection is Applied by the Responsible Entity* states "The SDT understands that in data exchanges between Control Centers, a single entity may not be responsible for both ends of the communication link." With the intent of the standard being to secure communications between Control Centers (including communication between two separate entities Control Centers), this will call for inter-entity cooperation to ensure both sides of link are secure. This is where the additional 12 months would be necessary, for coordination of efforts from both entities.	
Likes 0	

Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Dennis Sismaet - Northern California Power Agency - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Megan Wagner, Westar Energy, 6, 3, 1, 5; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steve Rose - City Water, Light and Power of Springfield, IL - 1,3,5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	

5. The SDT modified the draft Implementation Guidance for CIP-012 to provide examples of how a Responsible Entity could comply with the requirements. The draft Implementation Guidance does not prescribe the only approaches to compliance. Rather, it describes what the SDT believes would be effective ways to comply with the standard. See NERC's Compliance Guidance policy for information on Implementation Guidance. Do you agree with the draft Implementation Guidance? If you do not agree, or if you agree but have comments or suggestions for the draft Implementation Guidance, please provide your recommendation and explanation.

Thomas Foltz - AEP - 5

Answer	No
Document Name	

Comment

AEP requests the SDT consider including some statements in the Implementation Guidance to address the possibility that data requests made related to TOP-003 and/or IRO-010 include other data that is not Real-time Assessment data or Real-time monitoring data, and how the Responsible Entity could exclude this other data from the security requirements.

Likes 0	
Dislikes 0	

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

Overall, SRP does not agree with twenty-four (24) calendar months for the implementation of Requirements R1, as R1 and R2 from the second draft have been merged. Although SRP recognizes the SDT is not specifying the controls to be used to protect confidentiality and integrity, the only examples provided in the implementation guidance includes encryption. If there are other methods available to achieve the security objective, SRP asks the SDT to provide them. However, the only method available to achieve the proposed required objective, on the ICCP network, is to implement encryption. As FERC order 822 states on page 37, "if several registered entities have joint responsibility for a cryptographic key management system used between their respective Control Centers, they should have the prerogative to come to a consensus on which organization administers that particular key management system." Furthermore, the FERC order states on page 38, "While responsible entities are required to exchange real-time and operational planning data necessary to operate the bulk electric system using mutually agreeable security protocols, there is no technical specification for how this transfer of information should incorporate mandatory security controls." These are activities and specifications that must be created and agreed upon by all registered entities involved in the data transfer. As such the timeline is reliant on registered entities working together on a common solution and would not be achievable within 24 calendar months.

Additionally, if encryption fails, SRP would lose Real-time Assessment and Real-time monitoring and control data. There are many opportunities for encryption to fail that must be addressed. The implementation of encryption requires a pilot to truly understand and address the mechanisms of failure, the impacts encryption would cause on the exchange of the data, and the computing resources required. A pilot also requires a great amount of coordination to execute, not only within the industry, but may also include carriers, vendors, and possibly third-party encryption key program managers.

Because of the aforementioned reasons and concerns, SRP is recommending a phased implementation for CIP-012-1. A 24 month implementation is appropriate, but only for Requirement R1. The 24 months for R1 would provide time to coordinate and create an industry-wide solution. SRP is proposing the SDT include an additional 12 months for the plan implementation aspect of Requirement R1. The additional 12 months would be used for a pilot and course correction if needed, in addition to understanding, formulating, and executing maintenance strategies.

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF

Answer	No
Document Name	

Comment

Based upon NSRF comments to delete Requirement 1, Part 1.3 as identified under #2 of this comment form, the section within the Implementation Guidance titled “Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities” would need to be revised or eliminated. In addition, the Reference Model section of the Implementation Guide would also need be revised in those areas that reflect Responsible Entity accountability for other Responsible Entities.

The drafting team in earlier response to comments has stated that the Implementation Guidance would be submitted as a Standard Application Guide to NERC. This is imperative for Responsible Entities and Regional Entities to understand the intent and consistent application of this non-prescriptive Standard.

The NSRF questions when any type of Guidance is needed when the Standard is clearly written. As stated in FERC Order 693 section 253, FERC states “…The most critical element of a Reliability Standard is the Requirements. As NERC explains, “the Requirements within a standard define what an entity must do to be compliant . . . [and] binds an entity to certain obligations of performance under section 215 of the FPA.” If properly drafted, a Reliability Standard may be enforced in the absence of specified Measures or Levels of Non-Compliance”.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6

Answer	No
Document Name	

Comment

As with technical rationale any implementation guidance that can be condensed into clear, concise language should be moved into the CIP-012-1 as a defined requirement. Responsible Entities are audited to the Requirements in the Standard. In our opinion, leaving this much information as implementation guidance invites subjective audit interpretation and therefore unnecessarily increases compliance risk for the entity. The inclusion of acceptable means/methods within the verbiage of a Requirement does not necessarily make it prescriptive because the wording can state "or any other means that addresses the XXX risk". In addition, this type of guidance provides explicit compliance help which on its face increases overall BES reliability because entities may rely on the guidance to be compliant and not err by misinterpreting what can be done.

Likes 0	
Dislikes 0	

Response

Aaron Smith - Omaha Public Power District - 1,3,5,6

Answer	No
Document Name	

Comment

: Based upon NSRF comments to delete Requirement 1, Part 1.3 as identified under #2 of this comment form the section within the Implementation Guidance titled “Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities” would need to be revised or eliminated. In addition, the Reference Model section of the Implementation Guide would also need be revised in those areas that reflect Responsible Entity accountability for other Responsible Entities.

The drafting team in earlier response to comments has stated that the Implementation Guidance would be submitted as a Standard Application Guide to NERC. This is imperative for Resonsible Entities and Regional Entities to understand intent and consistent application of this non-prescriptive Standard.

The NSRF questions when any type of Guidance is needed when the Standard is clearly written. As stated in FERC Order 693 section 253, FERC states “…The most critical element of a Reliability Standard is the Requirements. As NERC explains, “the Requirements within a standard define what an entity must do to be compliant . . . [and] binds an entity to certain obligations of performance under section 215 of the FPA.” If properly drafted, a Reliability Standard may be enforced in the absence of specified Measures or Levels of Non-Compliance

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer	No
Document Name	

Comment

In the Implementation Guidance document, please specify what type of date under TOP-003 and IRO-010 should be excluded from the CIP-012 requirements.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Ginny Beigel, City of Vero Beach, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

The example “Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities, the language indicates the communication link endpoint is within a PSP. If the Control Center is rated as a Low Impact per the CIP-002-5.1a Attachment 1 Criteria 3.1, the term PSP does not apply and is not required by the Standard.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Megan Wagner, Westar Energy, 6, 3, 1, 5; - Douglas Webb

Answer	No
Document Name	

Comment

Kansas City Power and Light Company incorporates the Edison Electric Institute's response to Question No. 5.

Likes 0	
Dislikes 0	

Response

Richard Montgomery - Florida Municipal Power Agency - 3,4,5,6

Answer	No
Document Name	

Comment

The example “Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities, the language indicates the communication link endpoint is within a PSP. If the Control Center is rated as a Low Impact per the CIP-002-5.1a Attachment 1 Criteria 3.1, the term PSP does not apply and is not required by the Standard

Likes 0	
Dislikes 0	

Response	
Carol Chinn - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
The example “Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities, the language indicates the communication link endpoint is within a PSP. If the Control Center is rated as a Low Impact per the CIP-002-5.1a Attachment 1 Criteria 3.1, the term PSP does not apply and is not required by the Standard	
Likes 0	
Dislikes 0	
Response	
Joe McKinney - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
The example “Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities, the language indicates the communication link endpoint is within a PSP. If the Control Center is rated as a Low Impact per the CIP-002-5.1a Attachment 1 Criteria 3.1, the term PSP does not apply and is not required by the Standard.	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
The example “Identification of Responsibilities when the Control Centers are Owned or Operated by Different Responsible Entities, the language indicates the communication link endpoint is within a PSP. If the Control Center is rated as a Low Impact per the CIP-002-5.1a Attachment 1 Criteria 3.1, the term PSP does not apply and is not required by the Standard	
Likes 0	

Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	No
Document Name	

Comment

Generally, Exelon supports the Implementation Guidance, but ask the SDT to consider the following suggested changes:

1. Address how an entity might effectively identify Control Centers (as defined by the NERC Glossary) that would be exempted from complying with CIP-012-1 as a result of the newly developed Exemption 4.2.3 language.

2. There are many different approaches to mitigating the risk of unauthorized disclosure or modification of data in transit. Additional guidance that explores various approaches and evaluates their effectiveness in mitigating risk may be helpful before entities make implementation investments for CIP-012-1.

3. Exelon suggests the SDT consider removing or modifying the email example (last bullet on page 8) since email and the associated password exchange recommended (e.g., by phone) i "inconsistent with the requirements of Real-time data exchange" as indicated in the draft Implementation Guidance.

While Exwlon recognizes that approval of Implementation Guidance goes beyond the responsibility of the SDT, we suggest the final version of Implementation Guidance be approved by the ERO and posted with the Standard before any final ballot.

Likes 0	
Dislikes 0	

Response

Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns

Answer	No
Document Name	

Comment

Comments above in question 4 apply here as well.

Likes 0	
Dislikes 0	

Response

Eli Rivera - Central Electric Cooperative, Inc. (Redmond, Oregon) - NA - Not Applicable - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC ("CenterPoint Energy") agrees with Edison Electric Institute's (EEI) comments.	
Likes 0	
Dislikes 0	
Response	

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman	
Answer	No
Document Name	
Comment	
Please refer to MRO NERC Standards Review Forum (NSRF) comments.	
Likes 0	
Dislikes 0	
Response	

James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	
Comment	
In the Implementation Guidance document, please specify what type of date under TOP-003 and IRO-010 should be excluded from the CIP-012 requirements.	
Likes 0	
Dislikes 0	
Response	

Andrea Koch - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No

Document Name	

Comment
Generally, EEI supports the Implementation Guidance, but ask the SDT to consider the following suggested changes: 1. Address how an entity might effectively identify Control Centers (as defined by the NERC Glossary) that would be exempted from complying with CIP-012-1 as a result of the newly developed Exemption 4.2.3 language. 2. There are many different approaches to mitigating the risk of unauthorized disclosure or modification of data in transit. Additional guidance that explores various approaches and evaluates their effectiveness in mitigating risk may be helpful before entities make implementation investments for CIP-012-1. 3. EEI suggests the SDT consider removing or modifying the email example (last bullet on page 8) since email and the associated password exchange recommended (e.g., by phone) i "inconsistent with the requirements of Real-time data exchange" as indicated in the draft Implementation Guidance. While EEI recognizes that approval of Implementation Guidance goes beyond the responsibility of the SDT, we suggest the final version of Implementation Guidance be approved by the ERO and posted with the Standard before any final ballot.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment
On pages 5 and 6 of the Implementation Guidance document, BPA believes additional clarity is needed to identify each entity's responsibility, as follows: "Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity **A**, the Responsible Entity without operational obligations **(B)** for the communication link **Responsible Entity B** may demonstrate compliance by ensuring the communications link endpoint is within **B's** Control Center, which could be limited to including the communication link endpoint within **B's** PSP."

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	No
Document Name	

Comment	
The guidance provides encryption as a method. The industry has not been able to test security controls such as encryption, to ensure that reliability is not impacted. Concerned that encryption of data will create an adverse impact to reliability. It is unclear the amount of latency that may be added or amount of computing resources required to encrypt and decrypt this data every 6 seconds. Additionally, the burden should not be placed on a Registered Entity to prove that a neighbor's control room has the appropriate protections in place. We should only have the burden for our own control room.	
Likes 0	
Dislikes 0	
Response	
David Greyerbiehl - CMS Energy - Consumers Energy Company - 5	
Answer	No
Document Name	
Comment	
In the Implementation Guidance document, please specify what type of date under TOP-003 and IRO-010 should be excluded from the CIP-012 requirements.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
IRO-010-2 R3.3 and TOP-003-3 R5.3 already provide reliability assurance requirements for RCs, BAs, GOs, GOPs, TOPs, TOs, and DPs; and they are not presriptive. Consequently, CIP-012 is and its' draft implementation quidance are not needed. Additionally, NERC has a Standards Efficiency Initiative underway to get rid of standards and requirements such as CIP-012-1 and its' Requirement 1.	
Likes 0	
Dislikes 0	
Response	

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
IRO-010-2 R3.3 and TOP-003-3 R5.3 already provide reliability assurance requirements for RCs, BAs, GOs, GOPs, TOPs, TOs, and DPs; and they are not prescriptive. Consequently, CIP-012 is and its' draft implementation guidance are not needed. Additionally, NERC has a Standards Efficiency Initiative underway to get rid of standards and requirements such as CIP-012-1 and its' requirement 1.	
Likes 0	
Dislikes 0	
Response	
Tho Tran - Tho Tran On Behalf of: Lee Maurer, Oncor Electric Delivery, 1; - Tho Tran	
Answer	No
Document Name	
Comment	
Oncor supports EEI's comment.	
Likes 0	
Dislikes 0	
Response	
David Francis - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	No
Document Name	
Comment	
For the same reasons stated in response for question 4 with third party personnel entering a PSP	
Likes 0	
Dislikes 0	
Response	
Lynn Goldstein - PNM Resources - Public Service Company of New Mexico - 3	

Answer	No
Document Name	
Comment	
PNM Resources supports EEI’s comments on this question.	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
PacifiCorp agrees with modifications made to the implementation guidance, specifically the newly introduced paragraph, “Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP.” PacifiCorp would like the following edit added “or where other physical protections are applied.” PacifiCorp feels that this will allow entities flexibility where the devices that perform this are located within its location. PacifiCorp also likes the VPN examples provided. If the newly introduced paragraph or the VPN examples are removed or if the implementation guidance is not ERO-endorsed prior to the final ballot, PacifiCorp may alter its final vote.	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
MEC agrees with modifications made to the Implementation Guidance, specifically the newly introduced sentence, "Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP." MEC would like to see "or where other physical protections are applied." This will provide more flexibility for entities. MEC also likes the VPN example provided. Inclusion of the newly introduced sentence, the VPN example and ERO-endorsement of the implementation guidance are needed in the final version for MEC to vote yes on the final ballot.	
Likes 0	
Dislikes 0	
Response	

Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy agrees with the requirement based on the newly introduced paragraph in the Implementation Guidance, "Where the operational obligations of an entire communication link, including both endpoints, belong to the Control Center of another Responsible Entity, the Responsible Entity without operational obligations for the communication link may demonstrate compliance by ensuring the communications link endpoint is within its Control Center, which could be limited to including the communication link endpoint within a PSP." NV Energy would like the following edit added "or where other physical protections are applied." NV Energy believes that this will allow entities flexibility where their devices that perform this function are located within its location. NV Energy believes the VPN examples provided are necessary and should	

remain within the Guidance document. If the newly introduced paragraph or the VPN example are removed or if the implementation guidance is not ERO-endorsed prior to the final ballot, NV Energy may alter its final vote.	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
American Transmission Company LLC (ATC) agrees that the controls prescribed by CIP-006 satisfy CIP-012 Requirement R1 Parts 1.1 and 1.2, and appreciates being able to leverage Standards that are already implemented and enforceable as opposed to creating a new requirement. ATC cautions that this approach could re-create 'spaghetti' requirements placing Registered Entities in potential double jeopardy if conditions of non-compliance occur. ATC requests consideration of inclusion of statements in a CIP-012 CMEP Practice Guide to instruct Regional Compliance Enforcement Agencies to audit in a manner that does not place the Registered Entities at odds with both CIP-006-6 and CIP-012 for individual instances of potential non-compliance.	
Likes 0	
Dislikes 0	
Response	
Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC	
Answer	Yes
Document Name	
Comment	
No comments.	
Likes 0	
Dislikes 0	
Response	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	

Comment	
The SPP Standards Review Group would ask that the drafting team provide us some feedback on the next steps in their process on how they plan to get the Implementation Guidance Document formalized and coordinated with the CIP-012-1 Standard. From our prospective, this document was well put together and we would hate to see this document to be left out of the approval process for the CIP project.	
Likes 0	
Dislikes 0	
Response	
Steve Rose - City Water, Light and Power of Springfield, IL - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson	
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 RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
No comment at this time.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE prefers commenting on Implementation Guidance once the standard language is in its final form.	
Likes 0	
Dislikes 0	
Response	

6. The SDT believes proposed CIP-012-1 provides entities with flexibility to meet the reliability objectives in a cost effective manner. Do you agree? If you do not agree, or if you agree but have suggestions for improvement to enable more cost effective approaches, please provide your recommendation and, if appropriate, technical justification.

Dennis Sismaet - Northern California Power Agency - 6	
Answer	No
Document Name	
Comment	
IRO-010-2 R3.3 and TOP-003-3 R5.3 already provide reliability assurance requirements for RCs, BAs, GOs, GOPs, TOPs, TOs, and DPs; they provide flexibility to meet reliability objectives in a cost effective manner. Proposed CIP-012 does not, and is not needed. Additionally, NERC has a Standards Efficiency Initiative underway to get rid of standards and requirements such as CIP-012-1 and its' Requirement 1.	
Likes 0	
Dislikes 0	
Response	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
IRO-010-2 R3.3 and TOP-003-3 R5.3 already provide reliability assurance requirements for RCs, BAs, GOs, GOPs, TOPs, TOs, and DPs; they provide flexibility to meet reliability objectives in a cost effective manner. Proposed CIP-012 does not and is not needed. Additionally, NERC has a Standards Efficiency Initiative underway to get rid of standards and requirements such as CIP-012-1 and its' Requirement 1.	
Likes 0	
Dislikes 0	
Response	
David Greyerbiehl - CMS Energy - Consumers Energy Company - 5	
Answer	No
Document Name	
Comment	

More flexibility and less guidance could lead to inconsistency on requirement implementation among different entities.

Likes 0	
Dislikes 0	

Response

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper

Answer	No
Document Name	

Comment

Significant capital may need to be budgeted in order to implement architecture improvements to address the required computing resources for encryption and decryption of data. Encryption adds a burden for on-going maintenance and management. There is concern of the impacts on real-time operations for encryption and decryption of data.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA believes that if the data must be protected throughout the transmission, it would seem that could only be accomplished with encryption. For cases where the existing equipment is not capable of encryption, replacement will be costly and implementation lengthy. While the proposed standard and implementation guidance do not require encryption, no other solution seems viable.

Due to BPA's large amount of applicable data, access to funds and budget cycle, and resources to perform work required, the solution will be costly.

BPA also agrees with SRP's comments as follows:

"SRP does not agree the current standard and implementation plan can be executed in a cost effective manner. Encryption has been the only presented solution provided by auditors and SDT guidance to protect both confidentiality and integrity for the data within this scope. If the implementation timeframe remains at 24 months, more resources and capital will be required versus a phased implementation. A phased implementation provides the ability to not only ensure the most effective plan, but also provides the ability to plan more accurately within budget cycles. More importantly, if encryption fails, SRP would lose Real-time Assessment and Real-time monitoring and control data. SRP is concerned a 24 month implementation timeline would impact reliability as there are many opportunities for encryption to fail that must be addressed. This has a direct correlation on cost when addressing those opportunities during this timeframe.

Additionally, SRP would like to see reference models of methods that do not require encryption as a method to protect communications between Control Centers.”	
Likes 0	
Dislikes 0	
Response	
James Anderson - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	
Comment	
More flexibility and less guidance could lead to inconsistency on requirement implementation among different entities.	
Likes 0	
Dislikes 0	
Response	
Stephanie Burns - Stephanie Burns On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Stephanie Burns	
Answer	No
Document Name	
Comment	
ITC does not agree with this approach being cost effective. This is especially true for larger balancing authorities that own and pay for many routers and circuits to receive ICCP data they require for real time operation. Many routers deployed today may not have encryption capabilities and many circuits may not have adequate bandwidth to support additional encryption overhead. In addition the methods to connect to the control center such as the lease lines, or communication circuits, may need to change to accommodate the new protection requirements.	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	

Undetermined	
Likes 0	
Dislikes 0	
Response	
Joe McKinney - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Undetermined	
Likes 0	
Dislikes 0	
Response	
Carol Chinn - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Undetermined	
Likes 0	
Dislikes 0	
Response	
Richard Montgomery - Florida Municipal Power Agency - 3,4,5,6	
Answer	No
Document Name	
Comment	
Undetermined	

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Ginny Beigel, City of Vero Beach, 3; Lynne Mila, City of Clewiston, 4; Mike Blough, Kissimmee Utility Authority, 5, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	No
Document Name	

Comment

Undetermined

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF

Answer	No
Document Name	

Comment

More flexibility and less guidance could lead to inconsistency on requirement implementation among different entities.

Likes 0	
Dislikes 0	

Response

Richard Jackson - U.S. Bureau of Reclamation - 1

Answer	No
Document Name	

Comment

Reclamation recommends the term “plan” be replaced with the term “process” throughout the CIP-012-1 standard, Technical Rationale, Implementation Guidance, and associated documents. A plan is an unwarranted layer of compliance that does not improve the reliability of the BES. The processes an entity implements have defined controls that reduce the entity’s risks to the BES and thereby improve BES reliability.

Likes 0	
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 1,3,6

Answer	No
Document Name	

Comment

As currently worded in draft 4 we believe that there is too much potential risk to support a "yes" response to this question.

Likes 0	
Dislikes 0	

Response

Laura Nelson - IDACORP - Idaho Power Company - 1

Answer	No
Document Name	

Comment

The options for flexibility aren’t clearly presented in the draft standard and the language provided.

Likes 0	
Dislikes 0	

Response

Russell Martin II - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

SRP does not agree the current standard and implementation plan can be executed in a cost effective manner. Encryption has been the only presented solution provided by auditors and SDT guidance to protect both confidentiality and integrity for the data within this scope. If the implementation timeframe remains at 24 months, more resources and capital will be required versus a phased implementation. A phased implementation provides the ability to not only ensure the most effective plan, but also provides the ability to plan more accurately within budget cycles. More importantly, if encryption fails, SRP would lose Real-time Assessment and Real-time monitoring and control data. SRP is concerned a 24 month implementation

timeline would impact reliability as there are many opportunities for encryption to fail that must be addressed. This has a direct correlation on cost when addressing those opportunities during this timeframe. Additionally, SRP would like to see reference models of methods that do not require encryption as a method to protect communications between Control Centers.	
Likes 0	
Dislikes 0	
Response	
Warren Cross - ACES Power Marketing - 1,3,4,5 - MRO,WECC,Texas RE,SERC	
Answer	Yes
Document Name	
Comment	
ACES does agree with the cost effective approach, if the wording is revised from Control Center to Facility. A Control Center has much more compliance obligations than a Facility.	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 1,5	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
David Francis - Midcontinent ISO, Inc. - 2 - MRO,SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Quintin Lee - Eversource Energy - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Martin Sidor - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 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 RSC no Dominion	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeff Johnson - Jeff Johnson On Behalf of: Martine Blair, Sempra - San Diego Gas and Electric, 3, 5, 1; - Jeff Johnson	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Megan Wagner, Westar Energy, 6, 3, 1, 5; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Patricia Lynch - NRG - NRG Energy, Inc. - 5,6	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aaron Ghodooshim - FirstEnergy - FirstEnergy Corporation - 3, Group Name FirstEnergy Corporation	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Aubrey Short - FirstEnergy - FirstEnergy Corporation - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Maier - Intermountain REA - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Steve Rose - City Water, Light and Power of Springfield, IL - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - MRO, Group Name SPP Standards Review Group	
Answer	
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE does not have comments on this question.

Likes 0	
Dislikes 0	

Response

Andrea Koch - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

No comment

Likes 0	
Dislikes 0	

Response

Andy Fuhrman - Andy Fuhrman On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Andy Fuhrman

Answer	
Document Name	

Comment

This has not been determined due to the need for revisions to the proposed standard.

Likes 0	
Dislikes 0	
Response	
Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
No comment at this time.	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	
Document Name	
Comment	
Undetermined at this time.	
Likes 0	
Dislikes 0	
Response	