Consideration of Comments

Project Name:	2023-06 CIP-014 Risk Assessment Refinement | Draft 2
Comment Period Start Date:	9/23/2024
Comment Period End Date:	11/6/2024
Associated Ballots:	Project 2023-06 CIP-014 Risk Assessment Refinement CIP-014-4 AB 2 ST Project 2023-06 CIP-014 Risk Assessment Refinement Implementation Plan AB 2 OT

There were 64 sets of responses, including comments from approximately 135 different people from approximately 80 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. Do you agree with the modifications made in CIP-014-4 with modified Requirement R1 to address the issues identified in the SAR?

2. Do you agree with the modifications made in CIP-014-4 with new Requirement R2 to address the issues identified in the SAR?

3. Do you agree with the modifications made in CIP-014-4 with new Requirement R3 to address the issues identified in the SAR?

4. Do you agree with the modifications made in CIP-014-4 with new Requirement R4 to address the issues identified in the SAR?

5. Do you agree with the modifications made in CIP-014-4 with adding Requirement R5 to address the issues identified in the SAR?

6. Do you agree with the Implementation Plan for CIP-014-4?

7. Do you agree that CIP-014-4 is cost effective to address the reliability issue of physical security? If no, why not?

8. Provide any additional comments for the standard drafting team to consider, if desired.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Tennessee Valley Authority	Brian Millard	1,3,5,6	SERC	TVA RBB	Ian Grant	Tennessee Valley Authority	3	SERC
					David Plumb	Tennessee Valley Authority	1	SERC
					Armando Rodriguez	Tennessee Valley Authority	6	SERC
					Nehtisha Rollis	Tennessee Valley Authority	5	SERC
Jennie Wike	Jennie Wike		WECC	Tacoma Power	Jennie Wike	Tacoma Public Utilities	1,3,4,5,6	WECC
					John Merrell	Tacoma Public Utilities (Tacoma, WA)	1	WECC
					John Nierenberg	Tacoma Public Utilities (Tacoma, WA)	3	WECC
					Hien Ho	Tacoma Public Utilities (Tacoma, WA)	4	WECC
					Terry Gifford	Tacoma Public Utilities (Tacoma, WA)	6	WECC
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NPCC,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Kylee Kropp	Sunflower Electric Power Corporation	1	MRO
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
Eversource Energy	Joshua London	1		Eversource	Joshua London	Eversource Energy	1	NPCC
					Vicki O'Leary	Eversource Energy	3	NPCC
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Black Hills Corporation	Rachel Schuldt	6		Black Hills Corporation - All Segments	Travis Grablander	Black Hills Corporation	1	WECC
					Josh Combs	Black Hills Corporation	3	WECC
					Rachel Schuldt	Black Hills Corporation	6	WECC
					Carly Miller	Black Hills Corporation	5	WECC
					Sheila Suurmeier	Black Hills Corporation	5	WECC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC

					Michael Ridolfino	Central Hudson Gas & Electric Corp.	1	NPCC
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Sean Cavote	PSEG	4	NPCC
					Jason Chandler	Con Edison	5	NPCC
					Tracy MacNicoll	Utility Services	5	NPCC
					Shivaz Chopra	New York Power Authority	6	NPCC
					Vijay Puran	New York State Department of Public Service	6	NPCC

					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1,4,10	NPCC
					Joel Charlebois	AESI	7	NPCC
					John Hastings	National Grid	1	NPCC
					Erin Wilson	NB Power	1	NPCC
					James Grant	NYISO	2	NPCC
					Michael Couchesne	ISO-NE	2	NPCC
					Kurtis Chong	IESO	2	NPCC
					Michele Pagano	Con Edison	4	NPCC
					Bendong Sun	Bruce Power	4	NPCC
					Carvers Powers	Utility Services	5	NPCC
					Wes Yeomans	NYSRC	7	NPCC
					Chantal Mazza	Hydro Quebec	1	NPCC
					Nicolas Turcotte	Hydro Quebec	2	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Victoria Crider	Dominion Energy	3	NA - Not Applicable
					Sean Bodkin	Dominion Energy	6	NA - Not Applicable
					Steven Belle	Dominion Energy	1	NA - Not Applicable
					Barbara Marion	Dominion Energy	5	NA - Not Applicable
Public Utility District No. 1 of Chelan County	Tamarra Hardie	6		CHPD	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Rebecca Zahler	Public Utility District No. 1 of Chelan County	5	WECC

					Diane Landry	Public Utility District No. 1 of Chelan County	1	WECC
Tim Kelley	Tim Kelley		WECC	SMUD and BANC	Nicole Looney	Sacramento Municipal Utility District	3	WECC
					Charles Norton	Sacramento Municipal Utility District	6	WECC
					Wei Shao	Sacramento Municipal Utility District	1	WECC
					Foung Mua	Sacramento Municipal Utility District	4	WECC
					Nicole Goi	Sacramento Municipal Utility District	5	WECC
					Kevin Smith	Balancing Authority of Northern California	1	WECC

1. Do you agree with the modifications made in CIP-014-4 with modified Requirement R1 to address the issues identified in the SAR?

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
There is a disconnect between the listed responsibility in the Applicability Section 4.1 and R1. Does the Drafting team expect ALL TOPs to comply to R1, or ONLY those who have facilities that meet the criteria of Attachment 1? There is a high likelihood that auditors will interpret that ALL TOPs will have to complete R1 and show that they scored their facilities to determine applicability under Attachment 1. We suggest that the applicability section include ALL TOPs, and the requirements be modified to have all TOPs complete R1, then if they have not met the criteria of Attachment 1, they stop and have no additional compliance obligation. This would more clearly identify who is applicable to the Standard and eliminate a lot of ambiguity of what the auditors will need to verify that an entity is not applicable to the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. TOPs are not called out in requirement R1; Applicable TOPs are only required to comply with those requirements where they are explicitly called out.	
Tamarra Hardie - Tamarra Hardie On Behalf of: Diane E Landry, Public Utility District No. 1 of Chelan County, 3, 5, 1, 6; - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	No
Document Name	Near-Term vs Long-Term - Glossary of Terms.docx
Comment	
It appears that the Draft 2 changes to R1 clarified that the list is to be documented once every 36 months for all applicable stations "that are existing or planned to be in service within 36 months", which is an improvement from the previous draft version. This improves clarity but the R1 VRF Time Horizon still states that R1 applies to 'Long-term Planning Horizon', whereas the NERC Glossary of Terms defines the 'Near-Term Planning Horizon' as the window covering year 1 through 5. This requirement references 'within 36 months', so it is recommended that the R1 VRF Time Horizon language is updated to reference the 'Near-Term Transmission Planning Horizon'. Please see attached document "Near-Term vs Long-Term - Glossary of Terms".	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. NERC Time Horizons define "Long-term Planning" as "a planning horizon of one year or longer". This document is located on NERC public site: Document Portrait.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No

Document Name	

Comment
Eversource is looking for clarity on what is meant by the phrase "Planned to be in service." Eversource suggests either providing more prescriptive language around at what point in the process a project is considered "planned," or make the following change: Each Transmission Owner, at least once every 36 calendar months, shall document a list of applicable Transmission station(s) and Transmission substation(s) meeting any of the criteria in Attachment 1 that are either existing or planned, **as defined by the Transmission Owner,** to be in service within 36 calendar months**.**

Likes 0	
Dislikes 0	

Response
Thank you for your comments. "Planned to be in service" is a term taken from CIP-014-3 and the meaning is unchanged from the currently effective version. "Planned to be in-service" should be taken to mean all Transmission station(s) and Transmission substation(s) as modeled in the base cases for the Long-Term Transmission Planning Horizon.

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment
BPA believes the current language of R1 seems to be intended to create auditable documentation of the same outcome that is already achieved when a Registered Entity evaluates the current Applicability section. BPA suggests restoring applicability content to the Applicability section and changing R1 language for applicable Registered Entities to maintain the list of applicable stations or substations obtained through evaluation of the Applicability section.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The Drafting Team moved the language to an attachment due to the breadth of the language addition. The applicability language should remain where it is to allow entities an "off-ramp" to the standard requirements if they do not have applicable Transmission stations or substations.

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis

Answer	No
Document Name	

Comment
MPC strongly disagrees with the use of a 36-month timeframe for utilities who have not previously identified stations or substations as critical for the same reasons specified in our comments for Question 5.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. A directive of the SAR was to "correct any discrepancies between the study period, frequency of study, and the base case{s} a Transmission Owner uses." The Drafting Team chose a timeframe that balanced the directive of the SAR and the comments from industry to make the timeframe either shorter or longer than 36 months.

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment

The NPCC RSC is looking for clarity on what is meant by the phrase "Planned to be in service."

The NPCC RSC suggests either providing more prescriptive language around how a project is considered "planned," or make the following change:

Each Transmission Owner, at least once every 36 calendar months, shall document a list of applicable Transmission station(s) and Transmission substation(s) meeting any of the criteria in Attachment 1 that are either existing or planned, **as defined by the Transmission Owner,** to be in service within 36 calendar months.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. "Planned to be in service" is a term taken from CIP-014-3 and the meaning is unchanged from the currently effective version. "Planned to be in-service" should be taken to mean all Transmission station(s) and Transmission substation(s) as modeled in the base cases for the Near-Term Transmission Planning Horizon.

Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw

Answer	No
Document Name	

Comment

Oncor does not agree with the provision requiring consideration of Transmission station(s) and Transmission substation(s) that are planned to be in service within 36 calendar months because that time frame is beyond Oncor's accurate planning time frame, particularly given the large amount of growth currently being experienced in Oncor's service area. Instead, Oncor recommends that the provision be revised to require consideration of Transmission station(s) and Transmission substation(s) that are planned to be in service within 24 months.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. A directive of the SAR was to “correct any discrepancies between the study period, frequency of study, and the base case{s} a Transmission Owner uses.” The responsible entity is expected to perform an analysis with the best available information at the time of their analysis. The Drafting Team chose a timeframe that balanced the directive of the SAR and the comments from industry to make the timeframe either shorter or longer than 36 months.

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	

Comment

Please see the comments in our responses to Questions 2 through 8 of this questionnaire.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see responses to questions 2 through 8.

Jennifer Mcnally - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No
Document Name	

Comment

Duke Energy still has concerns that the timeline for the performance of R1 is not clear. We recommend that the assessment be performed within 36 months of *the completion* of the previous R1 assessment. We also recommend the end of R1 specify “planned to be in service in the model year three years out from the year in which the assessment is performed”. Years capture more accurately how planning is conducted. As written in draft 2, if the assessment is performed in October 2024, will using a planning model from Summer 2027 be acceptable? With the current language using 36 months, we have concerns that it would not be.

If the drafting team is not willing to consider referencing years for modeling, we recommend that they consider clarifying with a footnote that for planning purposes, the model year should be at least three years out from the start of the assessment.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The proposed implementation plan allows an adequate transition between CIP-014-3 R1 risk assessment and CIP-014-4 R5 risk assessment. The initial risk assessment required by Reliability Standard CIP-014-4 Requirement R5, must be completed on or before the effective date of the standard. Subsequent risk assessments shall be performed no later than 36 calendar months following the effective date of Reliability Standard CIP-014-4. In the previous version of CIP-014, the 30-month time frame and the 24-month planned-to-be-in-service date could, if not carefully applied, lead to gaps between models and study horizons. Per the Standard Authorization Request (SAR), CIP-014-4 has consolidated these multiple timelines into one. Requirement R1 is revised to ensure that each Transmission Owner establishes a list of applicable Transmission station(s) or Transmission substation(s) in accordance with Attachment 1. Aligning the 36 calendar months look ahead in Requirement R1 with the 36 calendar month risk assessment cycle ensures that system topology of the cases used to assess applicability is consistent with the system topology in the risk assessment models. Planned to be in-service" should be taken to mean all Transmission station(s) and Transmission substation(s) as modeled in the base cases for the Near-Term Transmission Planning Horizon.

If the assessment is performed in October 2024, using a planning model from Summer 2027 is acceptable.

Ellese Murphy - Ellese Murphy On Behalf of: Katherine Street, Duke Energy , 5, 6, 1, 1; - Ellese Murphy

Answer	No
Document Name	

Comment

Duke Energy still has concerns that the timeline for the performance of R1 is not clear. We recommend that the assessment be performed within 36 months of *the completion* of the previous R1 assessment. We also recommend the end of R1 specify "planned to be in service in the model year three years out from the year in which the assessment is performed". Years capture more accurately how planning is conducted. As written in draft 2, if the assessment is performed in October 2024, will using a planning model from Summer 2027 be acceptable? With the current language using 36 months, we have concerns that it would not be.

If the drafting team is not willing to consider referencing years for modeling, we recommend that they consider clarifying with a footnote that for planning purposes, the model year should be at least three years out from the start of the assessment.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The proposed implementation plan allows an adequate transition between CIP-014-3 R1 risk assessment and CIP-014-4 R5 risk assessment. The initial risk assessment required by Reliability Standard CIP-014-4 Requirement R5, must be completed on or before the effective date of the standard. Subsequent risk assessments shall be performed no later than 36 calendar months following the effective date of Reliability Standard CIP-014-4.

You assumption is correct. If the assessment is performed in October 2024, using a planning model from Summer 2027 is acceptable.

Kelley Sargent – Puget Sound Energy, Inc. – 3

Answer	No
Document Name	

Comment

We agree with the intent of CIP-014-4 to address issues identified in the SAR, however we would like to suggest changes to improve readability.

There is some interplay between R1 and R2 through Attachment 1 that makes identification of "applicable" stations confusing. R1 refers to Attachment 1 to identify "applicable" stations based on the weighting criteria in Table 1. Attachment 1 section 2.1 requires user to refer to R2 and apply proximity criteria to stations that were not applicable in R1.

To meet the intent of SAR to identify station "groups" that meet applicability criteria of Attachment 1, it may be best to identify station groups separately under R2 as a sub-requirement (i.e. move Section 2.1 from Attachment 1 to sub-requirement R2.2) and make Attachment 1 agnostic of stations or station groups. This separates intent of R1 and R2 and allows both requirements to reference Attachment 1 applicability criteria. R1 will identify individual stations that meet Attachment 1 applicability criteria. R2 will identify station groups with stations that were individually non-applicable under R1, but when combined with other non-applicable station(s) – based on proximity criteria of R2, may be applicable per Attachment 1 Table 1.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. These comments refer to a previous version of the draft standard as these changes have been addressed in the current draft standard up for ballot. As an example, requirement R2.1 in Attachment 1 is removed in the latest draft revision.

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

Answer	No
Document Name	

Comment

Salt River Project (SRP) agrees with EEI's suggestion to remove the word "proximity" from R3 to avoid using a term that is undefined in R2 and the comment that R3 Part 3.1.1 duplicates the concepts in R3 Part 3.1.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see responses to EEI's comments.

Bob Cardle – Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

The CIP-014-4 standard introduces a significant change by requiring the inclusion of stations within a ½-mile line of sight or easily accessible from a common roadway. However, the standard lacks clear guidelines for selecting stations. This could lead to inconsistencies and challenges in implementation, as different Transmission Owners and Transmission Operators may interpret and apply the criteria differently.

To improve clarity and ensure consistent implementation, the standard should provide more detailed guidance on the selection of stations, including specific criteria for evaluating lines of sight and ease of access from common roadways. This would help Transmission Owners and Transmission Operators to better understand the requirements and apply them consistently, ensuring the reliability and security of the electrical grid.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT made appropriate changes to address your suggestions.

Sean Bodkin – Dominion – Dominion Resources, Inc. – 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
The proposed 36 months for the period is not realistic as it is beyond a planning timeframe that would produce meaningful results. Limiting the period to 24 months accounts for issues such as supply chain, construction constraints, and outage planning to maintain a reliable system.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SAR scope is to “correct any discrepancies between the study period, frequency of study, and the base case{s} a Transmission Owner uses.” The Drafting Team chose a timeframe that balanced the scope of the SAR and the comments from industry to make the timeframe either shorter or longer than 36 months.	
Leshel Hutchings – AEP – 3	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support.	
Mark Garza – FirstEnergy – FirstEnergy Corporation – 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the proposed R1 for CIP-014-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Gary Trezza – Long Island Power Authority – 1 – NPCC	
Answer	Yes
Document Name	
Comment	

c) From a compliance perspective, it is recommended to provide more prescriptive language in the standard or within the technical rationale, to help entities in identifying planned projects around how a project is considered “planned,” or make the following change:

Each Transmission Owner, at least once every 36 calendar months, shall document a list of applicable Transmission station(s) and Transmission substation(s) meeting any of the criteria in Attachment 1 that are either existing or planned, **as defined by the Transmission Owner**, to be in service within 36 calendar months

b) With respect to the scoring in Attachment one, it’s unclear if transmission lines in series with a stepdown transformer would be included if the secondary voltage was 138 kV (as one example). Could the SDT identify if the scoring is based on the high side voltage or low side voltage? LIPA suggests a footnote identifying the voltage class used to determine qualification should be added below the scoring table.

c) In addition, since 500 kV facilities meet the Attachment 1 criteria 1, it seems as though the line item in the table for 500 kV and above may be removed as to avoid confusion.

Likes 0	
Dislikes 0	

Response

Thank you for your comments and support. “Planned to be in service” is a term taken from CIP-014-3 and the meaning is unchanged from the currently effective version. "Planned to be in-service" should be taken to mean all Transmission station(s) and Transmission substation(s) as modeled in the base cases for the Near-Term Transmission Planning Horizon.

Regarding the scoring of the Attachment 1, the summing of the lines for the aggregated value should be done regardless of whether or not the line terminates into a transformer.

Regarding your comment on the 500 kV Facilities in Attachment 1, the DT has addressed the issue by changing “0” to “N/A”.

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

The NPCC RSC is looking for clarity on what is meant by the phrase “Planned to be in service.”

The NPCC RSC suggests either providing more prescriptive language around how a project is considered “planned,” or make the following change:

Each Transmission Owner, at least once every 36 calendar months, shall document a list of applicable Transmission station(s) and Transmission substation(s) meeting any of the criteria in Attachment 1 that are either existing or planned, **as defined by the Transmission Owner,** to be in service within 36 calendar months.

Likes 0	

Dislikes 0	

Response

Thank you for your comments and support. “Planned to be in service” is a term taken from CIP-014-3 and the meaning is unchanged from the currently effective version."Planned to be in-service" should be taken to mean all Transmission station(s) and Transmission substation(s) as modeled in the base cases for the Near-Term Transmission Planning Horizon.

Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker

Answer	Yes
Document Name	

Comment

Cleco agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment and support.

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Submitted on behalf of Exelon - Segments 1 & 3

Likes 0	
Dislikes 0	

Response

Thank you for your comments and support.

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	Yes
Document Name	

Comment

EEI agrees with the modifications made in CIP-014-4 R1.

Likes 0	
Dislikes 0	

Response	
Thank you for your comments and support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy appreciates this revision from the previous draft which maintains overall continuity with previous versions of the standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and support.	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and support. Please see responses to EEI's comments.	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and support. Please see responses to EEI's comments.	

Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and support.	

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Matthew Nicklin - Southern Illinois Power Cooperative - 1,3,5 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Thank you for your support.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Amy Wilke - American Transmission Company, LLC - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Stefanie Burke - Portland General Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends updating the Applicability, 4.1 Functional Entities – 4.1.1 language to include solely and jointly owned facilities. Texas RE recommends the following revision (in bold): 4.1.1 Transmission Owner that owns **or jointly owns** a Transmission station(s) or Transmission substation(s) that meets the applicability criteria of Attachment 1.	
Likes 0	
Dislikes 0	
Response	
Thank you for comment. Please see the revised Standard to reflect this change.	

2. Do you agree with the modifications made in CIP-014-4 with new Requirement R2 to address the issues identified in the SAR?

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy in general supports the EEI comments and specifically has concerns with both line of sight and comon roadways being vague and subjective..	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT believes they have made appropriate changes to address the concerns. Additionally, please see the Drafting Team's response to EEI comments.	
Stefanie Burke - Portland General Electric Co. - 6	
Answer	No
Document Name	
Comment	
PGE supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI comments.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	No
Document Name	
Comment	
There needs to be more explanation on how the ½ mile criteria works with 2.1 and 2.2. As is written, the language in this section is confusing. Is the ½ mile the maximum distance to consider, but you need to consider the line of sight too criteria too? If two stations are within ½ mile of each other, but not in a direct line of sight, how does that impact the qualifications? ATC recommends eliminating 2.1 and 2.2 to remove the confusion or to have some clarifying examples or sentences in the standard to explain how these sections work together.	

Also, the inclusion of non-owned substations (i.e., the "irrespective of ownership" language) may also introduce further complications for TOs in their study analysis and should be further clarified what steps need to be taken to account for these non-owned stations.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The Drafting Team has reduced the distance criteria and provided specific reference points for measurement. Additionally, they have removed requirements R2.1 and R2.2 from the draft standard.

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

The CIP-014-4 standard introduces a significant change by requiring the inclusion of stations within a 1/2-mile line of sight or easily accessible from a common roadway. However, the standard lacks clear guidelines for selecting stations. This could lead to inconsistencies and challenges in implementation, as different Transmission Owners and Transmission Operators may interpret and apply the criteria differently.

To improve clarity and ensure consistent implementation, the standard should provide more detailed guidance on the selection of stations, including specific criteria for evaluating lines of sight and ease of access from common roadways. This would help Transmission Owners and Transmission Operators to better understand the requirements and apply them consistently, ensuring the reliability and security of the electrical grid.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT made appropriate changes to address your suggestions.

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

Answer	No
Document Name	

Comment

Salt River Project (SRP) supports the EEI comments and shares the concern with both line of sight and common roadways being vague and subjective.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT made appropriate changes to address the concerns. Additionally, please see the Drafting Team's response to EEI comments.

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

Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI comments.	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
See comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI comments.	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	No
Document Name	
Comment	
½ mile is a very wide separation criterion for adjacency. A reasonable separation within 200 feet or so seems a more practical consideration for adjacent substations that may be impacted by a single physical event. An event simultaneously impacting 2 stations with ½ mile separation will be difficult to protect from physical security standpoint and cost prohibitive. This aligns with PSE past comments (in June 2024): *It is not clear the type of events CIP-014-4 intends to address that can simultaneously impact 2 or more stations. The standard depends on physical security measures to mitigate such events, however mitigation to the extent may not be feasible nor cost effective.*	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance.	

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	

NIPSCO agrees with CenterPoint Energy Houston Electric, LLC (CEHE). *“Line of sight” or “ease of access” in Requirement R2 are arbitrary values and should not be used to comply with NERC requirements*

NIPSCO also agrees with AEP. *The intent is to identify close physical proximity such that a singular event could impact both stations; other ranges are irrelevant.* ***Emphasize explicitly in the standard language or Guidelines and Technical Basis that this considers only a single, simultaneous attack****. Considering non-simultaneous attacks makes the number of scenarios infinite and is not feasible to analyze or protect against.*

NIPSCO also agrees with Georgia Transmission Corp: *The intent of the requirement is understood and appreciated. However, the nature of the “single physical attack” needs clarification. Interpretations of this attack can range from events where elements are lost with some time delay between failures (gun shots for example) to a simultaneous loss of all elements (large explosion?). Clarity on the nature of the physical attack or parameters that can be applied to define the attack are needed to avoid differing interpretations of what event is to be studied and how this requirement is to be audited.*

Additionally, this guidance is appropriately located in the TPL space to clarify to planning entities what type of extreme event needs to be evaluated and subsequently communicated to the Transmission

Likes 0	
Dislikes 0	
Response	

Thank you for the comment. The Drafting Team has removed requirements R2.1 and R2.2 from the draft standard.

Ellese Murphy - Ellese Murphy On Behalf of: Katherine Street, Duke Energy , 5, 6, 1, 1; - Ellese Murphy	
Answer	No
Document Name	
Comment	

Duke Energy does not support the language proposed for R2. The fundamental issue still exists that R2 is not tied to likely threat vectors identified within an entity’s security program. We understand that due to the sequencing of the requirements that linking to R8 is not feasible but do think that more general reference to likely threat vectors identified by the entity would create a more meaningful requirement. If the Drafting Team prefers to create R2 in a way that has a uniform distance requirement for proximity sites, we believe that the distance should be based on ballistic threats and a more reasonable distance would be 1000ft. We do not find the ½ mile radius to be technically justified. Duke Energy supports prescribing that line of sight be addressed in documented criteria but does not support prescribing ease of access from a common roadway and supports EEI’s comments on this. Ease of access from a common roadway is far more subjective than line of sight and less immediately relevant for a coordinated attack.

It is also still unclear how the criteria can use sites in proximity irrespective of ownership and Duke Energy supports EEI membership’s concern on this issue. The requirement to study sites identified in R2 that are not owned by your company creates an unclear path forward for conducting the studies. It is likely that many of these proximity sites will not even be part of the BES and could be owned by entities that do not have any BES assets. There is no mechanism to force these entities to provide the data that would be needed to perform the R3 analysis and comply with CIP-014. We encourage the Drafting Team to consider whether it makes more sense to account for sites of differing ownership when they are determined to be applicable in accordance with Requirement R1 by a different registered entity. Duke Energy recommends the following language for R2:

Each Transmission Owner shall have documented criteria to determine their Transmission station(s) or Transmission substation(s), that are adjacent, adjacent meaning having a perimeter fence within 1000 ft of the perimeter fence of an applicable Transmission station or Transmission substation documented in Requirement R1, that could be impacted by a single physical attack that from likely threats vectors. The Transmission Owner must also include in their criteria identification of adjacent transmission station(s) or substation(s) that are owned and determined to be applicable in accordance with Requirement R1 by a different registered entity. From the adjacent Transmission station(s) or Transmission substation(s), the criteria shall also identify Transmission station(s) or Transmission substation(s) within line of sight from a single location without obstruction of an applicable Transmission station or Transmission substation documented in Requirement R1.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Gail Elliott – Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	No
Document Name	

Comment

Comments: {C}{C}{C} {C}{C}ITC does not support the changes identified in R2. ITC recommends R2 and all its subparts be revised. The proposed R2 language by the drafting team provides concerns due to the high probability of missing a substation located within the 0.5 mile radius as the TO would not have the required information of all existing nearby facilities nor have the information necessary to identify that the electric facility is a transmission station. Furthermore, a TO is to identify any future transmission stations that could be constructed within 3 years which would be even more difficult to locate. ITC proposes the following for R2 and its sub-parts.

If the TO has identified that it has multiple fenced areas on a site that it considers as one station, there is not clarity if R2 would be applicable. Would these instead just apply to R1?

R2. Each Transmission Owner shall have documented criteria to determine those of its Transmission station(s) and Transmission substation(s) within ½ mile of an applicable Transmission station or Transmission substation documented in Requirement R1 that could be impacted by a single physical attack. The criteria shall address at a minimum the following:

{C}2.1 Line of sight between multiple Transmission station(s) or Transmission substation(s) from a single location without obstruction.

If an entity has multiple fenced areas on a property site but they consider these all one station would they be non-compliant if the loss of all sites was not studied.

Finally, the identification of a physically adjacent site to an applicable station as being critical has issues if the site is not owned by the same entity as the applicable site. If mitigation measures are needed, which entity shall determine the scope of these mitigations and who should pay for them.

Likes 0	

Dislikes 0	

Response

Thank you for the comment. Ownership and identification of proximate transmission stations and substations is an explicit requirement of the SAR (see Project Scope item 5). Proximate substation identification can be achieved through publicly available tools such as Google Maps and cross-referenced with model data to identify specific transmission facilities. The Drafting Team assumes the responsible entity will choose a model that reflects the requirements of the standard and contains appropriate future projects, including distance from applicable substations owned by the responsible entity.

Jennifer Mcnally - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No
Document Name	

Comment

Duke Energy does not support the language proposed for R2. The fundamental issue still exists that R2 is not tied to likely threat vectors identified within an entity's security program. We understand that due to the sequencing of the requirements that linking to R8 is not feasible but do think that more general reference to likely threat vectors identified by the entity would create a more meaningful requirement. If the Drafting Team prefers to create R2 in a way that has a uniform distance requirement for proximity sites, we believe that the distance should be based on ballistic threats and a more reasonable distance would be 1000ft. We do not find the ½ mile radius to be technically justified. Duke Energy supports prescribing that line of sight be addressed in documented criteria but does not support prescribing ease of access from a common roadway and supports EEI's comments on this. Ease of access from a common roadway is far more subjective than line of sight and less immediately relevant for a coordinated attack.

It is also still unclear how the criteria can use sites in proximity irrespective of ownership and Duke Energy supports EEI membership's concern on this issue. The requirement to study sites identified in R2 that are not owned by your company creates an unclear path forward for conducting the studies. It is likely that many of these proximity sites will not even be part of the BES and could be owned by entities that do not have any BES assets. There is no mechanism to force these entities to provide the data that would be needed to perform the R3 analysis and comply with CIP-014. We encourage the Drafting Team to consider whether it makes more sense to account for sites of differing ownership when they are determined to be applicable in accordance with Requirement R1 by a different registered entity. Duke Energy recommends the following language for R2:

Each Transmission Owner shall have documented criteria to determine their Transmission station(s) or Transmission substation(s), that are adjacent, adjacent meaning having a perimeter fence within 1000 ft of the perimeter fence of an applicable Transmission station or Transmission substation documented in Requirement R1, that could be impacted by a single physical attack that from likely threats vectors. The Transmission Owner must also include in their criteria identification of adjacent transmission station(s) or substation(s) that are owned and determined to be applicable in accordance with Requirement R1 by a different registered entity. From the adjacent Transmission station(s) or Transmission substation(s), the criteria shall also identify Transmission station(s) or Transmission substation(s) within line of sight from a single location without obstruction of an applicable Transmission station or Transmission substation documented in Requirement R1.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, the DT has removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

John Pearson - ISO New England, Inc. - 2

Answer	No

Document Name	
Comment	

R2, when combined with other requirements such as R3.3, can lead to an overly conservative outcome. In R2, stations can be grouped together due to being in close proximity to each other. Then testing is done to understand the impact of the loss of the proximity group under R3.3. By way of example, assume that there are two stations near each other, one being a very large station with numerous transmission lines connecting to it, where if tested individually, would result in significant concerns on the remaining system. The second station is a very small station, that if tested individually would have no meaningful impact on the remaining system. When they are grouped together, the results would not be meaningfully worse than the event occurring at the large, well-interconnected station, yet the second station would get swept into needing CIP-014 upgrades simply because of its proximity, rather than the results of the test being worse. This would require customers to pay for unnecessary physical protection measures to be installed at the smaller station.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The proximate station would have no physical security obligations if the applicable substation was protected, as protecting the applicable substation invalidates the physical attack being studied under requirement R5.

Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1

Answer	No
Document Name	

Comment

TAL does not agree with a Transmission Owner making a determination on a Transmission station or Transmission substation that they do not have ownership. This should be the responsibility of the station or substation owner to make those determinations.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. It is unclear to the Drafting Team what “making a determination” means. If it means identifying the location of proximate Transmission stations or substations, then identification of ownership is not needed to make such a determination. If “making a determination” implies ascertaining physical security upgrades which have cost implications, the proximate Transmission station or substation has no obligation to protect its site if the applicable Transmission station or substation does so as the result of an R5 risk assessment.

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments

Answer	No
Document Name	

Comment

Black Hills Corporation agrees with EEI’s suggestion to strike R2, Part 2.2. R2, Part 2.2 is not needed to meet the primary objectives in the SAR.

Black Hills Corporation also agrees with EEI’s suggestion to add examples to the technical rationale describing how to apply the ½ mile distance criteria and line of sight criteria.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	No
Document Name	

Comment

Ameren would like more clarification around what to do when there are multiple substations close to each other. We would also like more clarification around why surrounding substations are being included. More definition is needed around what conditions are assumed at the remote site, such as the disabling of protection at both ends.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has made modifications to the section on substations in proximity to each other and added clarifying language regarding remote clearing. The inclusion of surrounding substations was a requirement of the SAR (Project Scope Item 5).

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	No
Document Name	

Comment

Further clarification required to stations in proximity.

Understandably the standard is trying to not be too prescriptive. Is the expectation that the TO use their own discretion to determine which stations are impacted by proximity stations? And then take actions accordingly? Could the wording in the standard result in entities all performing their own methodology (from very limited to thorough) which will result in a request to form another SDT to review and be more prescriptive because they are inconsistent.

Clarification is required on what is the expectation and responsibility of a TO inform a neighboring entity they station needs to be reviewed to comply with CIP-014, if it is in proximity. How much can this be enforced by one entity to another. What do we do if its not a transmitter, but a GO.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, the DT has removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access. The first balloted draft was more prescriptive than the second and the Drafting Team received many comments to make the second draft less prescriptive. The proximate station would have no physical security obligations if the applicable substation was protected as protecting the applicable substation invalidates the physical attack being studied under requirement R5.

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin

Answer	No
Document Name	

Comment

Complying with this requirement may present several challenges.

(R2) We believe having a clearly defined proximity criteria of ½ mile is acceptable.

It should be made clear that both sub-requirements (R2.1 and R2.2) are required to be applicable with an “and”.

(R2.1) It may be challenging to establish, document and audit what constitutes as “line of sight”. Factors such as terrain, vegetation, and existing infrastructure can obscure the view. Additionally, these factors may be point-in-time and line of sight could be obscured during initial risk assessment but visible during an Audit site visit.

(R2.2) Assessing the ease of access from roadways requires a thorough understanding of public access. Identifying all routes to a facility, especially in rural or less developed areas, can be challenging.

Also, this requirement may bring new Registered Entities that do not meet R1 into scope. Following the identification of an applicable substation per R2 owned by another Registered Entity, how will a TO ensure that necessary security measures are put in place by the adjacent TO that does not own CIP-014 R1 applicable substations?

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

The proximate station would have no physical security obligations if the applicable substation was protected as protecting the applicable substation invalidates the physical attack being studied under requirement R5.

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

Complying with this requirement may present several challenges.

(R2) We believe having a clearly defined proximity criteria of ½ mile is acceptable.

It should be made clear that both sub-requirements (R2.1 and R2.2) are required to be applicable with an "and".

(R2.1) It may be challenging to establish, document and audit what constitutes as "line of sight". Factors such as terrain, vegetation, and existing infrastructure can obscure the view. Additionally, these factors may be point-in-time and line of sight could be obscured during initial risk assessment but visible during an Audit site visit.

(R2.2) Assessing the ease of access from roadways requires a thorough understanding of public access. Identifying all routes to a facility, especially in rural or less developed areas, can be challenging.

Also, this requirement may bring new Registered Entities that do not meet R1 into scope. Following the identification of an applicable substation per R2 owned by another Registered Entity, how will a TO ensure that necessary security measures are put in place by the adjacent TO that does not own CIP-014 R1 applicable substations?

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

The proximate station would have no physical security obligations if the applicable substation was protected as protecting the applicable substation invalidates the physical attack being studied under requirement R5.

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	

Comment

We request clarification of the proximity requirement to be physical distance of ½ mile, not electrical distance.

We request clarification of acceptable proximity obstruction exclusions such as trees, buildings, highway, etc.

Clarify that if an adjacent substation is radial from the substation under study, it is not applicable.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Richard Vendetti - NextEra Energy - 5	
Answer	No
Document Name	
Comment	

NextEra supports the comments provided by EEI below:

EEI provides the following revisions for consideration:

EEI suggests striking Requirement R2, Part 2.2. The Project Scope described in the SAR for Project 2023-06 does not include ease of access as a needed revision to CIP-014-3 but does explicitly include line-of-sight. Ease of access from a common public roadway may be an appropriate consideration in some scenarios, but it is not appropriate in all cases such as rural scenarios where a common public roadway or common roadway does not exist between stations or where an alternative such as the transmission right of way are more likely access paths. The inclusion of the ½ mile distance and line-of-sight requirement address the primary objectives in the SAR, and the "shall address at a minimum" language provides flexibility to consider additional criteria.

Additionally, EEI is concerned with the inclusion of the "irrespective of ownership" language in Requirement R2 because it is not possible to compel non-registered entities, or registered entities that are not subject to CIP-014 to share the information required by the proposed Standard. While we do not have revised language to recommend, we ask the drafting team to consider ways to manage differing ownership that are scoped to registered entities who must comply with CIP-014, or to make revisions that provide flexibility by allowing the Transmission Owner to determine how to manage differing ownership as part of their criteria or methodology.

EEI asks the drafting team to consider adding examples or explanations to the technical rationale describing:

a. ½ mile distance – Please add a justification for selecting ½ mile as the appropriate distance. Clarify if the drafting team intended for the distance to be based on driving distance, or as the crow flies.

b. Line of sight – Please clarify by adding examples of how to apply this. For example, if an entity performed site visits during the summer, line of sight could be impacted by trees/vegetation during the summer that would not impact line of sight during the winter.

Likes 0	
Dislikes 0	
Response	

Thank you for the comment. Please see response to EEI comments.

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	No
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #2.

Likes 0	

Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI comments.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
SERC appreciates the ongoing efforts to refine the CIP-014 Risk Assessment portion of the standard. As commented in previous ballots, SERC believes the removal of subrequirement 2.1 would provide additional clarity as those elements are difficult to measure and may change seasonally and over time, and create an uncertain mix of objective and subjective criteria. SERC also believes that further clarity could be added to the ½ mile threshold in R2, to clarify that ½ mile is the distance between closest substation fencelines or Elements – as some large EHV substations may have nearly ¼ mile or more of fenceline among one side.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI comments.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

EEI provides the following revisions for consideration: EEI suggests striking Requirement R2, Part 2.2. The Project Scope described in the SAR for Project 2023-06 does not include ease of access as a needed revision to CIP-014-3 but does explicitly include line-of-sight. Ease of access from a common public roadway may be an appropriate consideration in some scenarios, but it is not appropriate in all cases such as rural scenarios where a common public roadway or common roadway does not exist between stations or where an alternative such as the transmission right of way are more likely access paths. The inclusion of the ½ mile distance and line-of-sight requirement address the primary objectives in the SAR, and the “shall address at a minimum” language provides flexibility to consider additional criteria. Additionally, EEI is concerned with the inclusion of the “irrespective of ownership” language in Requirement R2 because it is not possible to compel non-registered entities, or registered entities that are not subject to CIP-014 to share the information required by the proposed Standard. While we do not have revised language to recommend, we ask the drafting team to consider ways to manage differing ownership that are scoped to registered entities who must comply with CIP-014, or to make revisions that provide flexibility by allowing the Transmission Owner to determine how to manage differing ownership as part of their criteria or methodology. EEI asks the drafting team to consider adding examples or explanations to the technical rationale describing: a. ½ mile distance – Please add a justification for selecting ½ mile as the appropriate distance. Clarify if the drafting team intended for the distance to be based on driving distance, or as the crow flies. b. Line of sight – Please clarify by adding examples of how to apply this. For example, if an entity performed site visits during the summer, line of sight could be impacted by trees/vegetation during the summer that would not impact line of sight during the winter.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access. The information required from proximate substations can be gathered from other sources (GIS maps, models, etc.) if the proximate facility owner does not provide information and as such, determination of “irrespective of ownership” in the proposed standard is achievable.	
Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	No
Document Name	
Comment	
Oncor does not agree that the modifications made in CIP-014-4 Requirement R2 to address the issues identified in the SAR because the proposed sub-requirements in R2 are still ambiguous and fail to create the consistent approach in the identification of infrastructure critical to the operation of the BPS as sought with the SAR. Due to varying geographical locations of facilities and the overall flexibility to document the criteria used to determine proximity, inconsistencies in approaches to perform risk assessments will remain. We recommend that R2.1 and R2.2 be replaced with specific and measurable criteria. For example, the Director of National Intelligence Joint Counterterrorism Assessment Team (JCAT) has published bomb threat standoff distances in which the mandatory evacuation distances for an SUV/VAN explosive threat is 400 feet. Guidelines such as these are used by Physical Security Professionals when performing the evaluation required by CIP-014-3 R6. For consistency, we recommend that a distance between 400 feet to 1000 feet be specified in CIP-014-4 R2.	

Additionally, we request clarification of the proposed R2 language concerning voltage classes applicable to stations in proximity. While the proposed R2 language points to R1 stations concerning proximity, and R1 points to Attachment 1, in which lines less than 200 kV are not applicable, it is unclear that the same "less than 200 kV" exclusion applies to those facilities that are in physical proximity to facilities to which R1 is applicable. We request that R2 be clarified to state that only facilities above 200 kV and in proximity to applicable facilities under R1 are to be considered.

As revised, R2 now places the burden on a Transmission Owner ("TO") to track those Transmission stations and Transmission substations that are within ½ mile of that TO's own Transmission station or Transmission substation even if they are *owned by other parties*. Not all TOs willingly disclose the exact location of their stations or substations, and some consider the geographic locations of their stations and substations to constitute CEII. Both of these scenarios will impede a TO's ability to obtain the necessary location information. In addition, this proposed approach could present significant issues for entities that are in competition with one another, which is the case in certain areas of Texas in which multiple entities are certificated to provide service in the same geographic area or in areas containing numerous Transmission stations or Transmission substations owned by various entities in close proximity.

We also point out that the language in R2 "that could be impacted by a single physical attack" is too vague and could create significant disparities in how threat assessments are performed in accordance with R2. Under CIP-014-4 R2, each TO would be responsible for determining what an "impact" is and when it could occur. As a result, this vague requirement may create challenges when stations or substations are within the same line of sight from a single location or share access from a common roadway, but are owned by different entities. If those different TO are not aligned in how "impact" is determined and the procedures and processes implemented to ensure compliance with CIP-014-4 R2, then disagreements between those entities on whether their stations or substations could have been impacted by a single physical attack could arise. Such disagreements could make determining compliance with CIP-014-4 R2 for each of the disagreeing entities particularly difficult.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Location of proximate substations can be identified using common public access tools without the need to coordinate with another entity. Additionally, non-BES facilities should not be considered for proximity.

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment

The NPCC RSC has a concern in the event of two entities disagreeing with a line of sight risk assessment. We suggest adding a common form and/or process to reconcile CIP-014 line of sight assessments disagreements so to avert non-compliance by either entity.

We would recommend issuing formal guidance on a "line of sight" and "common roadway" and how to assess those two terms.

Likes 0	
Dislikes 0	

Response	
Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, the DT have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CEHE) believes “line of sight” or “ease of access” in Requirement R2 are arbitrary values and should not be used to comply with NERC requirements. CEHE in general supports the EEI comments and specifically has concerns about the inclusion of the “irrespective of ownership” language in Requirement R2 because it is not possible to compel non-registered entities, or registered entities that are not subject to CIP-014 to share the information required by the proposed Standard. While we do not have revised language to recommend, we ask the drafting team to consider ways to manage differing ownership that are scoped to registered entities who must comply with CIP-014, or to make revisions that provide flexibility by allowing the Transmission Owner to determine how to manage differing ownership as part of their criteria or methodology.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access. The Drafting Team believes that the information required from proximate substations can be gathered from other sources (GIS maps, models, etc.) if the proximate facility owner does not provide information and as such, determination of “irrespective of ownership” in the proposed standard is achievable.	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see response to EEI comments.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No

Document Name	
Comment	

The intent of the requirement is understood and appreciated. However, the nature of the “single physical attack” needs clarification. Interpretations of this attack can range from events where elements are lost with some time delay between failures (gun shots for example) to a simultaneous loss of all elements (large explosion?). Clarity on the nature of the physical attack or parameters that can be applied to define the attack are needed to avoid differing interpretations of what event is to be studied and how this requirement is to be audited.

Additionally, this guidance is appropriately located in the TPL space to clarify to planning entities what type of extreme event needs to be evaluated and subsequently communicated to the Transmission Owner.

Likes 0	
Dislikes 0	
Response	

Thank you for the comment. However, the DT notes that the nature of the “single physical attack” is defined by modeling assumptions in Requirements R2 & R3. Please see the Technical Rationale Document for additional information.

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

Answer	No
Document Name	
Comment	

The NPCC RSC has a concern in the event of two entities disagreeing with a line of sight risk assessment. We suggest adding a common form and/or process to reconcile CIP-014 line of sight assessments disagreements so to avert non-compliance by either entity.

We would recommend issuing formal guidance on a “line of sight” and “common roadway” and how to assess those two terms.

Likes 0	
Dislikes 0	
Response	

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3

Answer	No
Document Name	
Comment	

PNM and TNMP support EEI comments

Likes 0	

Dislikes 0	

Response

Thank you for the comment. Please see response to EEI comments.

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	No
Document Name	

Comment

LG&E/KU supports most of the modifications in Requirement R2. The 1/2 mile radius provides a clear boundary to the area considered proximate. However, we also support the additional feedback and asks for clarification submitted in EEI's comments.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. Please see response to EEI comments

Gary Trezza - Long Island Power Authority - 1 - NPCC

Answer	No
Document Name	

Comment

This particular requirement does not identify a need for a TO with facilities that meet the requirement to inform an adjacent TO (i.e., a TO that is a different owner) who's facilities fall under the distance identified under R2. It seems unreasonable for a TO to have to assess another TO's facilities or know if their future plans would create an impact to them due to proximity of where the facility is installed. LIPA would suggest adding language requiring TO's who identify facilities under R2 to coordinate and notify adjacent TO's in support of their own assessment.

There is also a concern in the event two different entities disagree with a line of sight risk assessment. We suggest adding a common form and/or process to reconcile CIP-014 line of sight assessments / disagreements so to avert non-compliance by either entity.

We would recommend issuing formal guidance on a "line of sight" and "common roadway" and how to assess those two terms.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

The Drafting Team has structured the draft standard such that collaboration with adjacent entities is allowed but not required to comply with the standard.

Leshel Hutchings - AEP - 3

Answer	No
Document Name	

Comment

The intent is to identify close physical proximity such that a singular event could impact both stations; other ranges are irrelevant. **Emphasize explicitly in the standard language or Guidelines and Technical Basis that this considers only a single, simultaneous attack**. Considering non-simultaneous attacks makes the number of scenarios infinite and is not feasible to analyze or protect against.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT has revised the standard in response to these concerns.

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis

Answer	No
Document Name	

Comment

MPC concurs with the MRO NSRF's request for clarification.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to MRO comments.

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA recognizes a significant improvement in the language of R2, however BPA finds the proximity text is still highly subjective. BPA asks "What does the process look like when one Registered Entity brings in owners of other facilities?" BPA sees a potentially dramatic increase in modeling concerns considering multiple Facilities owned by multiple entities. BPA believes there is insufficient detail about expected actions when new Facilities are added due to proximity and recommends adding clarity to the expected actions. As an example, when a new facility is added, a study should be conducted with the option of ruling out the criticality of the new facility. Finally, BPA believes the intent of CIP-014 is changing from identifying a very small number of absolutely critical substations to requiring Registered Entities to expand their lists due to proximity.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Tamarra Hardie - Tamarra Hardie On Behalf of: Diane E Landry, Public Utility District No. 1 of Chelan County, 3, 5, 1, 6; - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD

Answer	No
Document Name	

Comment

The ‘line of sight’ and ‘ease of access’ ambiguous term usage concerns remain from the previous draft. However, the removal of the ‘close enough proximity’ language and the addition of the ‘within ½ mile of an applicable Transmission station(s)’ was an improvement for R2. This change adds some clarity and removes some ambiguity from this requirement that was present in previous draft versions.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

The NPCC RSC has a concern in the event of two entities disagreeing with a line of sight risk assessment. We suggest adding a common form and/or process to reconcile CIP-014 line of sight assessments disagreements so to avert non-compliance by either entity.

We would recommend issuing formal guidance on a “line of sight” and “common roadway” and how to assess those two terms.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	No
Document Name	
Comment	

The NPCC RSC has a concern in the event of two entities disagreeing with a line of sight risk assessment. We suggest adding a common form and/or process to reconcile CIP-014 line of sight assessments disagreements so to avert non-compliance by either entity.

We would recommend issuing formal guidance on a “line of sight” and “common roadway” and how to assess those two terms.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of
access.

Kevin Conway - Western Power Pool - 4

Answer	No
Document Name	
Comment	

The 1/2-mile radius is arbitrary and has no technical justification. This part of the requirement should be removed, and the documented criteria required by R2 should require where substations are within line-of-site and how the threat of a single attack is mitigated through distance or other mitigation.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	
Comment	

NV Energy appreciates the addition of the ½ mile bright line criteria to remove ambiguity and subjectivity.

NV Energy requests that the SDT provide clarity on the following items:

Clarify in the rationale that the Transmission stations within a ½ mile of an applicable Transmission station is based on distance "as the crow flies" and not electrical distance.

Clarify using examples of what are acceptable proximity exclusion obstructions such as trees, buildings, highway, etc. or is this up to each individual assessment criteria?

Clarify in the rationale if an adjacent substation is radial from the substation under study, then it is not applicable. Add examples to the rationale to address the various scenarios involving a substation under study and any adjacent substations meeting the ½ mile proximity. For example: Are they faulted simultaneously or individually with or without the same damage or inoperability? Are these questions up to each individual assessment methodology?

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Based on Attachment 1, radial Transmission stations and Transmission substations are included as part of the assessment.

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon does not object to the current language of R2. The inclusion of the ½ mile threshold provides beneficial specificity to the requirement. To strengthen the durability of this ½ mile threshold we request the drafting team to add the technical basis for this threshold into the standard.

Submitted on behalf of Exelon - Segments 1 & 3

Likes 0	
Dislikes 0	

Response

Thank you for your comment and suggestion. The threshold has been decreased to 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line), and this has been addressed in the Technical Rationale Document.

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

For section 2.2, request clarification on “ease of access”. Does a fence, gate, or a speedbump limit the ease of access concern? Recommend providing guidance in either the standard or technical rationale.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

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

Answer	Yes
Document Name	

Comment

Tri-State supports MRO NSRF comments regarding the need for clarity.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see responses to MRO NSRF’s comments.

Ben Hammer - Western Area Power Administration - 1

Answer	Yes
Document Name	

Comment

Please provide R2.1 rationale for line of sight distance as this is likely different than other distances (such as the conductor distance) and could require additional analysis to determine. Also, please identify acceptable obstructions.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the proposed R2 for CIP-014-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
The addition of 1/2 mile of applicable Transmission station(s) and Transmission substation(s) provides enough guidance to adhere to 2.1 and 2.2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Matthew Nicklin - Southern Illinois Power Cooperative - 1,3,5 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends R2 be clarified to state “within ½ mile of **straight areal distance from** an applicable transmission station or transmission substation documented in Requirement R1.	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

The Drafting Team has reduced the separation requirement, added clarification on the reference point for measurement and added language in the Technical Rationale to explain the reason for the chosen distance. Additionally, they have removed requirements R2.1 and R2.2, which pertained to line-of-sight and ease of access.

3. Do you agree with the modifications made in CIP-014-4 with new Requirement R3 to address the issues identified in the SAR?

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

The loss of any single substation under R3 is essentially studied as part of the TPL standards yearly. The R3 requirement should be limited to those facilities identified in R2. This avoids duplication of other standards and work, especially for smaller organizations that do not have dedicated planning staff.

Transmission Owners do not have planning staff to do steady-state and dynamic studies, that is a Transmission Planner function. Transmission Owners are responsible to build and maintain transmission assets. R3 should be focused on Transmission Planners to complete these studies and distribute them to the TO entities to implement action plans when there are negative findings. TOs should be required to provide information needed to the Transmission Planners so the studies can be relevant and accurate.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. While similar, the event studied in CIP-014 is different from the NERC Category P5 contingency studied in TPL-001-5. For instance, TPL-001 contingencies due to unspecified causes, whereas CIP-014 is focused specifically on physical attacks. Additionally, TPL-001 focuses on system reliability, whereas CIP-014 focuses on the reliability and stability of an Interconnection. For these reasons alone, the DT believes that the assumptions for each should be separate and distinct from each other.

The addition of Transmission Planner to the Applicability section is outside of the scope of the Project 2023-06 SAR.

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	

We recommend removing the word “proximity” and making it consistent with R2 wording.

We recommend the SDT to consider that planning and simulation studies (Part 3.1) are not solely be located in a physical security standard regardless of how load is lost (hurricane, fire, earthquake, physical attack, etc.)

We also recommend removing “proximity” from 3.3 and make it consistent with the rest of the standard.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment.

The use of “proximity” in requirement R3.3 is not intended to define a term but is used only in a descriptive sense.
The DT believes that the word “proximate” in Requirement R2 and the word “proximity” in Requirement R3 are in agreement.

The scope of this standard is limited to physical security.

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

We recommend removing the word “proximity” and making it consistent with R2 wording.

We recommend the SDT to consider that planning and simulation studies (Part 3.1) are not solely be located in a physical security standard regardless of how load is lost (hurricane, fire, earthquake, physical attack, etc.)

We also recommend removing “proximity” from 3.3 and make it consistent with the rest of the standard.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The use of “proximity” in requirement R3.3 is not intended to define a term but is used only in a descriptive sense.

The scope of this standard is limited to physical security.

Mark Flanary - Midwest Reliability Organization - 10

Answer	No
Document Name	

Comment

A suggestion for R3.1: As currently written the terms "instability, uncontrolled separation, or Cascading within an Interconnection" are unclear within the context of a given Entity and do not provide a solid basis for the Entity to implement their program or for oversight to compare. MRO recommends that the Entity be required to define these terms in the context of the studies within their system and to identify criteria when "instability, uncontrolled separation, or Cascading within an Interconnection" occur.

A suggestion for R3.2: MRO finds the term "more likely to contribute" to be vague and subjective. Consider enhancing by adding the requirement to document the rationale for the condition selections; for example justification based on historical events, and conditions identified in other studies.

The proposed language for R3.3 motivates MRO's negative vote on this draft. Specifically, the use of the term "fault" opens the door to the usage of less severe faults. We recommend changing "fault" to "a fault that will cause the most severe consequences at that substation" to ensure the most serious scenario is studied. We believe the currently drafted language will reduce the effectiveness of the standard.

Likes 0	

Dislikes 0	

Response

Thank you for the comment.

The Drafting Team has reduced the level of specificity with regard to reliability criteria based on numerous comments from industry and thus chose not to define instability, uncontrolled separation, or Cascading.

“More likely to contribute” has been removed from the standard.

The DT believes that simulation of a fault is a reasonable assumption for possible events that could impact a single Transmission station or Transmission substation, and for events that could simultaneously impact multiple Transmission stations or Transmission substations. The DT does not believe that specification of fault type (e.g., 3-phase faults or single-line-to-ground faults) was mandated by the SAR, and furthermore believes that such a specification is a) too prescriptive and b) potentially creates scenarios that do not match up with plausible threat vectors assessed and managed by corporate security personnel complying with CIP-014 Requirements R7 – R10. The DT furthermore believes that simulation of a no-fault event is not a reasonable assumption for physical attacks under CIP-014. While plausible, no-fault events are not in keeping with the direction of the SAR.

Tamarra Hardie - Tamarra Hardie On Behalf of: Diane E Landry, Public Utility District No. 1 of Chelan County, 3, 5, 1, 6; - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD

Answer	No
Document Name	

Comment

The ‘line-of-sight’ and ‘ease of access’ term usage concerns mentioned in comment section 2 above also applies to R3 since R3.3 refers to R2 station applicability. However, edits to R3.4.2 appear to provide more flexibility to entities and are an improvement from the previous draft version.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The DT agreed with the industry that the terms “Line of sight” and “ease of access” are too vague, therefore these terms have been removed from the standard. Instead, the DT clarified the issue of proximity in Requirements R2 and R3.

James Keele - Entergy - 3

Answer	No
Document Name	

Comment

[R3.3] states the analysis should include a fault at the R1 applicable station and a fault at any proximate R2 station. [R3.4] states the fault simulation should assume loss of communication and protection system at the station being studied. Existing language is not clear whether one is to assume loss of protection system on only the proximate facility or both the applicable and proximate facility at the same time.

Adrian Lazo:

[R3.4.2.] Consider removal of the word “more” in requirement. “More conservative” implies the actual clearing times are known and you then assume a more conservative value. However, you would use a conservative estimate when the actual clearing times are not known.

3.4.2. Actual or more conservative estimates of clearing times shall be used unless otherwise technically substantiated.

Adrian Lazo:

[R3.2.2.] Adding unstable generators tripped from the dynamic stability study to the steady-state contingency definition would create overly conservative results. Historically, both studies have been done in parallel and not directly informed each other.

Steady-state studies typically assume constant power loads where power does not vary with changes in voltage magnitude. This is a valid assumption for steady state studies but in reality, loads do not behave this way and differs greatly from how loads are represented in dynamic studies.

For dynamic studies the composite load model (CMLD) has seen increased adoption among utilities and more accurately reflects the aggregate behavior of motors. The model includes parameters which dictate fractions of the motor load components that do not restart, even if voltage recovers above the undervoltage trip thresholds. There is currently no industry consensus on whether this fraction of non-restart able motor loss is consequential or non-consequential load loss. Entergy’s stance is that this is consequential load loss as it’s impossible to prevent and would occur even for normally cleared faults due to typical undervoltage time delays of 2-3 cycles. Consequential load loss is commonly excluded from steady-state load loss criteria.

In summary, reflecting tripped generators from the stability study to the steady-state study would only make sense if loads were also reduced by the fraction of non-restart able motor loss. This would be extremely tedious as there is currently no practical way to achieve this with the tools available to Transmission Planners. There may be other issues that may need to be considered. Removal of the “including any tripped elements from dynamic simulations” language or a written exclusion for unstable generators should be considered.

Likes 0	
Dislikes 0	

Response

The DT believes that the language as currently proposed is appropriate. While there are commonly used generic clearing times for remote clearing that are consistent across the industry, actual clearing times can be shorter or longer depending on conditions and design considerations at an individual Transmission Owner. The difference of a few cycles can have a significant impact on the transient behavior of generating units, therefore, it is required that the risk analysis use actual or more conservative clearing time. Please see the Technical Rationale for further clarification.

Requirement R3.2.2 was removed from the standard.

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	No
Document Name	

Comment

Eversource has concerns with the phrase “other unacceptable post-event response within an Interconnection” in R3.1.1. A Transmission Planner may not know what is considered acceptable post-event response for an entire Interconnection. Direction on how to coordinate with the entire Interconnection or a minimum expectation should be provided. For example, Eversource is located in ISO New England; ISO New England may have certain acceptable frequency of 58 Hz but Pennsylvania may have a stricter 59 Hz limit, unbeknownst to the Transmission Planner. Another example

would be power flow, where an acceptable amount of generation loss would not be known for an entire Interconnection, as impacts could occur outside the TP's immediate area.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. This language has been removed from the standard.	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
BPA believes section 3.2.2 will significantly increase the steady state processes and consequently increase overall costs. BPA finds the wording of 3.2.2 is too prescriptive, therefore the language should be removed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Requirement R3.2.2 was removed from the standard.	
Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis	
Answer	No
Document Name	
Comment	
MPC concurs with the MRO NSRF's request for clarification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to MRO NSRF's comments.	
Leshel Hutchings - AEP - 3	
Answer	No
Document Name	
Comment	

1. Please either remove 3.1.1 or merge it into 3.1.
2. The phrase “other unacceptable post-event response within an interconnection” in 3.1.1 should be limited to instability, uncontrolled separation, or Cascading. This phrase is too open ended and ill-defined. It is enough to now be adding generation loss and load loss to the instability, uncontrolled separation, and Cascading of the approved version. The SDT now has five measures of station criticality; there is no need to open the door for more. Therefore, please replace this phrase with “instability, uncontrolled separation, or cascading” or remove it entirely.
3. For clarity, we suggest expanding 3.1 to a numbered list as follows: “Technically supported thresholds and rationale for determining: 3.1.1 the amount of acceptable load loss, 3.1.2 the amount of acceptable generation loss, 3.1.3 post-event response resulting in instability having a critical impact on the operation of the interconnection, 3.1.4 uncontrolled separation, and 3.1.5 Cascading”
4. The phrase “System conditions that are more likely to contribute” in 3.2 is too open ended and ill-defined. Please replace this with “one System peak load case or System off-peak load case, whichever may be more likely to contribute...”
5. 3.2.2. Feeding dynamic outages into steady state cases will lead to significant nonconvergence issues in steady state if applied in the contingency or even if a base case is created with these outages because the appropriate timing delay cannot be reflected. If outages are applied individually and manually post-contingency this will be a significant increase in the burden of the steady state analysis.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

1. Requirement R3.1.1 has been removed from the standard.

2. “Other unacceptable post-even response…” language has been removed from the standard.

3. Requirement R3.1 has been revised. Please see proposed changes.

4. The DT has removed the phrase and modified the sub-Requirement as: A provision that steady-state and dynamic simulations shall each be performed using a System peak Load case and a System Off-Peak Load case.

5. Requirement R3.2.2 has been removed from the standard.

Ben Hammer - Western Area Power Administration - 1

Answer	No
Document Name	

Comment

Please consider language that is clear/specific regarding what is required, at a minimum, to meet the requirements of the standard. Having language in a requirement saying “and any additional considerations recognized as” and “that are more likely to” are too general and broad. This introduces challenges, inconsistencies, and confusion regarding what specifically must be considered in order to meet compliance with the requirement.

Suggested language is provided below. Reordering of the subparts of Requirement R3 should be considered depending on the language that is ultimately chosen.

R3. Each Transmission Owner shall have a documented risk assessment methodology for evaluating the loss due to a physical attack of each applicable Transmission station(s) and Transmission substation(s) documented in Requirement R1 and Transmission substation(s) or Transmission station(s) determined to be in proximity per Requirement R2. The methodology shall include, at a minimum, the following:

3.1. Technical rationale for determining the amount of acceptable post-event load loss and generation loss.

3.2. The criteria or methodology used to identify instability, uncontrolled separation, or Cascading within an Interconnection.

3.3 Rationale for the System conditions selected for performing the studies.

3.4 For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, analysis shall include the following:

3.4.1. A Fault at the applicable Transmission station or Transmission substation and each Transmission station or Transmission substation identified in accordance with Requirement R2 as being in proximity to the applicable Transmission station or Transmission substation.

3.4.2. The removal of all Elements that the Protection System and other automatic controls are expected to disconnect for each event.

3.4.3. Steady-state simulations shall include any additional tripped Elements identified from the dynamic simulation of an event.

3.4.4. Dynamic simulations that assume the loss of communication and the Protection System at the Transmission station(s) or Transmission substation(s) shall use the following:

3.4.4.1 Delayed (remote-end) clearing times unless otherwise technically substantiated.

3.4.4.2 Actual or more conservative estimates of clearing times unless otherwise technically substantiated.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT believes that the majority of these suggestions are organizational rather than substantial. In particular, the DT notes that Western Area Power Administration's proposed R3.4 and R3.4.1 do not adequately address how to simulate fault scenarios for both lists identified as part of Requirements R1 and R2, and for that reason the DT has elected to proceed with the 3rd draft Requirement R3 as posted. Please see the latest Requirement R3 language and the latest Technical Rationale document for additional detail.

Gary Trezza - Long Island Power Authority - 1 - NPCC

Answer	No
Document Name	

Comment

a) We recommend removing the word “proximity” from R2 and R 3.3 and making the wording consistent with the R2 wording.

b) The wording for R3.2, R3.3 and R3.4 is written a little out of context with the intent of R3, which is to develop a documented risk assessment methodology. It is recommended to consider moving R3.2, R3.3 and R3.4 to be sub-requirements of R5.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The use of “proximity” in requirement R3.3 is not intended to define a term but is used only in a descriptive sense. The DT believes that the word “proximate” in Requirement R2 and the word “proximity” in Requirement R3 are in agreement.

Requirements R3.2, R3.3 and R3.4 should be defined in the methodology before they're studied as part of the R5 risk assessment.	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	No
Document Name	
Comment	
Additional clarity (explanation) is requested for R3, 3.3 regarding the intent of the language for analysis that includes a Fault ("…analysis shall include a Fault at the applicable Transmission station…") since there could be different interpretations within the industry.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Due to the comments received from the industry from the previous ballot, the DT has removed the specificity regarding the type of Fault to apply.	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Southern Company appreciates the efforts the drafting team made to add flexibility to the simulation of a physical attack as it pertains to Requirement R3.3. However, the SAR differentiates the CIP-014 assessment from other planning assessments in that "the risk assessment requires the entire transmission station to be considered as rendered inoperable or damaged as the result of physical attack rather than just particular elements electrically connected to a single electrical disturbance." Southern Company requests the SDT add more clarity to Requirement R3.3 to address this portion of the SAR while still maintaining some flexibility that was evident in this draft. Otherwise, we are concerned the industry will have vastly different interpretations of this requirement that lead to inconsistency in analysis and verification.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to the MRO NSRF comments. Greater specificity for this requirement was rejected in the previous ballot.	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	

PNM and TNMP support EEI comments. Additionally, language in 3.2 seems quite vague. What are “conditions that are more likely to contribute to”? Please consider adding technical rationale/guidance.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the DT’s response to EEI comments. Additionally, the DT has modified the requirement to remove “conditions that are more likely…” language and instead added “using a System peak Load case and a System Off-Peak Load case”.

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment

If an identified site is found to cause instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged as a result of a physical attack during steady state analysis, then there should be no reason to perform dynamic analysis on that site.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT has added clarifying language to allow the entity to forego dynamic analysis if steady state analysis indicates a site is found to cause instability, uncontrolled separation or Cascading within an Interconnection when rendered inoperable or damaged.

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

Answer	No
Document Name	

Comment

We recommend removing the word “proximity” and making it consistent with R2 wording.

We recommend the SDT to consider that planning and simulation studies (Part 3.1) are not solely be located in a physical security standard regardless of how load is lost (hurricane, fire, earthquake, physical attack, etc.)

We also recommend removing “proximity” from 3.3 and make it consistent with the rest of the standard.

The NPCC RSC has concerns with the phrase “other unacceptable post-event response within an Interconnection” in R3.1.1. A Transmission Planner may not know what is considered acceptable post-event response for an entire Interconnection. Direction on how to coordinate with the entire Interconnection or a minimum expectation should be provided. For example, a company is located in ISO New England; ISO New England may have certain acceptable frequency of 58 Hz, but Pennsylvania may have a stricter 59 Hz limit, unbeknownst to the Transmission Planner. Another example would be power flow, where an acceptable amount of generation loss would not be known for an entire Interconnection, as impacts could occur outside the TP’s immediate area.

Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The use of "proximity" in requirement R3.3 is not intended to define a term but is used only in a descriptive sense. Requirement R3.1.1 has been removed from the draft standard.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
Developing steady-state and dynamic simulation criteria is a planning function and should not be required of a Transmission Owner. The sub-requirements go further into addressing what a transmission planning study should include but applies this requirement incorrectly to the Transmission owner. The intent of R3 is more appropriately applicable to the TPL body of standards. CIP-014 should reference output from a study performed in accordance with a clearly defined TPL requirement for an extreme event involving the loss of an applicable Transmission station(s) or substation(s).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The Drafting Team believes that this suggestion is out of scope for Project 2023-06.	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	No
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to EEI's comments.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	

CEHE supports EEI's comments for requirements 3.1 and 3.3. In addition, CEHE has concerns with planning assessments to simulate "the loss of communications and system protection" as listed in Requirement 3, part R3.4. CEHE believes it is an unnecessary burden on TPs, where now TPs are required to perform steady state assessments but also stability simulations. The loss of any single substation under R3 is already studied annually as part of TPL standards. Requirement R3, Part 3.2.2 goes beyond the scope of what is documented in the SAR by requiring additional steady-state analysis after the steady-state and dynamic simulations show acceptable system response. The SAR specifically states that "[t]o ensure that a station is effectively identified as non-critical, registered entities need to have performed both steady-state and dynamic studies" but does not go into further detail about performing another steady-state analysis that includes any tripped Elements from the dynamic simulations. We suggest striking Requirement R3, Part 3.2.2.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the DT's response to EEI's comments.

Requirement R3.2.2 has been removed from the proposed standard.

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	No
Document Name	

Comment

We recommend removing the word "proximity" and making it consistent with R2 wording.

We recommend the SDT to consider that planning and simulation studies (Part 3.1) are not solely be located in a physical security standard regardless of how load is lost (hurricane, fire, earthquake, physical attack, etc.)

We also recommend removing "proximity" from 3.3 and make it consistent with the rest of the standard.

The NPCC RSC has concerns with the phrase "other unacceptable post-event response within an Interconnection" in R3.1.1. A Transmission Planner may not know what is considered acceptable post-event response for an entire Interconnection. Direction on how to coordinate with the entire Interconnection or a minimum expectation should be provided. For example, a company is located in ISO New England; ISO New England may have certain acceptable frequency of 58 Hz, but Pennsylvania may have a stricter 59 Hz limit, unbeknownst to the Transmission Planner. Another example would be power flow, where an acceptable amount of generation loss would not be known for an entire Interconnection, as impacts could occur outside the TP's immediate area.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The use of "proximity" in requirement R3.3 is not intended to define a term but is used only in a descriptive sense.

Requirement R3.1.1 has been removed from the draft standard.

Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	No
Document Name	
Comment	
The referenced "System conditions that are more likely to contribute to instability, uncontrolled separation, or Cascading within an Interconnection" mentioned in R3.2 need to be clarified. In ERCOT, a TO can explain why it selected the study cases it did, but each utility can only select those cases based on its experience with its own system. If there are specific "System conditions" that need to be studied, those "System conditions" should be specified and explained in R3.2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The Drafting Team has updated the model requirements language in Requirement R3.2.	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	No
Document Name	
Comment	
AZPS agrees with EEI's comments regarding the inclusion of load loss and generation loss within Part 3.1 which is not required by the SAR. Additionally, AZPS supports EEI's proposed language to resolve this issue.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to EEI's comments.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI proposes the following revisions for consideration: The term "proximity" is not used in Requirement R2. EEI suggests removing it from Requirement R3 and its sub parts. R3. Each Transmission Owner shall have a documented risk assessment methodology, including criteria for steady-state and dynamic simulations, for evaluating the loss due to a physical attack of each applicable Transmission station(s) and Transmission substation(s) documented in Requirement R1	

and Transmission substation(s) or Transmission station(s) determined per Requirement R2. The methodology shall include, at a minimum, the following:

Requirement R3, Parts 3.1 and 3.1.1 include duplicative concepts that could lead to confusion implementing and/or documenting the requirement parts. As an example, Requirement R3 requires the Transmission Owner to have a documented risk assessment methodology, including criteria for steady-state and dynamic simulations. Requirement R3, Part 3.1 requires the methodology to include technically supported thresholds and rationale, and Part 3.1.1 restates the requirement for the technical rationale to include steady-state and dynamic system response to events. EEI suggests consolidating the requirement parts as written below:

3.1 Technically supported thresholds and rationale for determining the amount of acceptable load loss, the amount of acceptable generation loss post-event response, and any additional considerations recognized as resulting in instability, uncontrolled separation, or Cascading within an Interconnection.

Requirement R3, Part 3.2.2 goes beyond the scope of what is documented in the SAR by requiring additional steady-state analysis after the steady-state and dynamic simulations show acceptable system response. The SAR specifically states that "[t]o ensure that a station is effectively identified as non-critical, registered entities need to have performed both steady-state and dynamic studies" but does not go into further detail about performing another steady-state analysis that includes any tripped Elements from the dynamic simulations. We suggest striking Requirement R3, Part 3.2.2.

Requirement R3, Part 3.3 could be further clarified and reference to proximity should be removed in favor the reference to R2, we suggest the following language:

3.3 For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, analysis shall include a Fault **in the simulation** at the applicable Transmission station or Transmission substation and **then at** each Transmission station or Transmission substation identified in accordance with Requirement R2.

Requirement R3, Part 3.4 is not clear as written. If the intention of the drafting team is for 3.4 to require fault simulations that assume the loss of communication and Protection System at all of the Transmission station(s) or Transmission substation(s) studied under Requirements R3, Parts 3.2 and 3.3 simultaneously, we suggest the following revision:

3.4. Fault simulations that assume the loss of communication and Protection System at **all of** the Transmission station(s) or Transmission substation(s) studied under Requirement R3, Parts 3.2 and 3.3.

EEI appreciates that drafting team's revision to Requirement R3, Part 3.4.2 to provide flexibility in the clearing times used, however, by stating "Actual or more conservative" entities will still need to calculate the actual clearing times in order to validate that the estimates are more conservative. We suggest:

3.4.2. Actual or conservative estimates of clearing times shall be used unless otherwise technically substantiated.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The use of "proximity" in requirement R3.3 is not intended to define a term but is used only in a descriptive sense.

Requirement R3.1.1 has been removed from the draft standard.

Requirement R3.2.2 has been removed from the draft standard.

Modifications and clarifications have been made to Requirements R3.3 and R3.4. Please see draft standard.

The DT believes that “more” is a necessary clarifying term in Requirement R3.4.2. While there are commonly used generic clearing times for remote clearing that are consistent across the industry, actual clearing times can be shorter or longer depending on conditions and design considerations at an individual Transmission Owner. The difference of a few cycles can have a significant impact on the transient behavior of generating units, therefore, it is required that the risk analysis use actual or more conservative clearing time

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	No
Document Name	

Comment

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the DT’s response to EEI’s comments.

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

Answer	No
Document Name	

Comment

Tacoma Power supports the changes. However, there does not appear to be an existing requirement within TPL-008, TPL-001, or MOD-032 for a TO with a non-applicable substation to provide sufficient detail about backup relaying schemes to an adjacent TO in order to fulfill R3.2.1. We recommend the standard drafting team ensure there is adequate access to relaying information via a request chain from the TO to PC to adjacent PC to TO.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. NERC standard PRC-027 has similar requirements around communication and coordination of protection settings. Given this, the DT believes that it is appropriate to require similar details for CIP-014.

Dave Krueger - SERC Reliability Corporation - 10

Answer	No
Document Name	

Comment

SERC appreciates the ongoing efforts to refine the CIP-014 Risk Assessment portion of the standard. SERC believes the elimination of the specific details in previous requirements 3.4 and 3.5 and the use of the single word ‘fault’, that the standard has drifted from having clarity and consistency in the requirements of how such extreme events are simulated across different utilities, contrary to the specificity mentioned in SAR Scope item 3 and without explanation in the Technical Rationale for the change. There is also no visible consideration or measurement of the reliability risks of excluding certain fault types from these forward-looking studies, nor an ongoing mechanism in R3.3 for historic analysis of faults as proposed by some other commenters.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The DT does not agree with specifying or excluding certain Fault types to be studied, or with requiring historic analysis of Faults.

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

Answer	No
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #3.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the DT's response to EEI's comments.

Richard Vendetti - NextEra Energy - 5

Answer	No
Document Name	

Comment

NextEra supports the comments provided by EEI below:

EEI proposes the following revisions for consideration:

The term "proximity" is not used in Requirement R2. EEI suggests removing it from Requirement R3 and its sub parts.

R3. Each Transmission Owner shall have a documented risk assessment methodology, including criteria for steady-state and dynamic simulations, for evaluating the loss due to a physical attack of each applicable Transmission station(s) and Transmission substation(s) documented in Requirement R1 and Transmission substation(s) or Transmission station(s) determined to be in proximity per Requirement R2. The methodology shall include, at a minimum, the following:

Requirement R3, Parts 3.1 and 3.1.1 include duplicative concepts that could lead to confusion implementing and/or documenting the requirement parts. As an example, Requirement R3 requires the Transmission Owner to have a documented risk assessment methodology, including criteria for steady-state and dynamic simulations. Requirement R3, Part 3.1 requires the methodology to include technically supported thresholds and rationale, and Part 3.1.1 restates the requirement for the technical rationale to include steady-state and dynamic system response to events. EEI suggests consolidating the requirement parts as written below:

1.1 Technically supported thresholds and rationale for determining the amount of acceptable load loss, the amount of acceptable generation loss post-event response, and any additional considerations recognized as resulting in instability, uncontrolled separation, or Cascading within an Interconnection. The technical rationale shall include:

1.1.1 Steady-state and dynamic system response to events that could lead to load loss, generation loss, and other unacceptable post-event response

Requirement R3, Part 3.2.2 goes beyond the scope of what is documented in the SAR by requiring additional steady-state analysis after the steady-state and dynamic simulations show acceptable system response. The SAR specifically states that “[t]o ensure that a station is effectively identified as non-critical, registered entities need to have performed both steady-state and dynamic studies” but does not go into further detail about performing another steady-state analysis that includes any tripped Elements from the dynamic simulations. We suggest striking Requirement R3, Part 3.2.2.

Requirement R3, Part 3.3 could be further clarified and reference to proximity should be removed in favor the reference to R2, we suggest the following language:

3.3 For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, analysis shall include a Fault **in the simulation** at the applicable Transmission station or Transmission substation and **then at** each Transmission station or Transmission substation identified in accordance with Requirement R2 as being in proximity to the applicable Transmission station or Transmission substation.

Requirement R3, Part 3.4 is not clear as written. If the intention of the drafting team is for 3.4 to require fault simulations that assume the loss of communication and Protection System at all of the Transmission station(s) or Transmission substation(s) studied under Requirements R3, Parts 3.2 and 3.3 simultaneously, we suggest the following revision:

3.4. Fault simulations that assume the loss of communication and Protection System at **all of** the Transmission station(s) or Transmission substation(s) studied under Requirement R3, Parts 3.2 and 3.3.

EEI appreciates that drafting team’s revision to Requirement R3, Part 3.4.2 to provide flexibility in the clearing times used, however, by stating “Actual or more conservative” entities will still need to calculate the actual clearing times in order to validate that the estimates are more conservative. We suggest:

3.4.2. Actual or more conservative estimates of clearing times shall be used unless otherwise technically substantiated.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the DT’s response to EEI’s comments.

Jamison Cawley - Nebraska Public Power District - 1

Answer	No
Document Name	

Comment

Please provide more specificity around the clearing times referenced in R3.4. The phrase “more conservative estimates” is vague as it opens the door to different interpretations by various entities. A specific timeframe should be specified in cycles to clarify the intent of the Standard.

There are two issues to consider, both being identified during a compliance audit. One issue considers loss of communications at the primary substation, and the other considers any adjacent or proximate substations.

First, is the simulation intended to have a communication outage prior to a fault or simultaneous with the fault, and if not simultaneous how far in advance of the fault is the communications outage expected to occur (this issue was a point of contention during an audit)? Please clarify the language of the Standard regarding loss of communications for protection schemes and the timing of loss of communications between multiple substations.

Second, regarding timing of loss of communications at adjacent substations, if an assessment methodology allows for pilot schemes to trip high speed without communications such as DCB lack of blocking signal or DCUB unblocking schemes when the guard signal is lost during the trip window allowing a highspeed trip this is technically substantiated.

Additionally, the assumption of a simultaneous fault and/or loss of communications on each element of two adjacent substations, potentially up to ½ mile apart, seems impossible to technically justify and should not be required for the risk assessment.

Please reconcile the phrase “more likely to contribute” in Requirement 3.2 with the phrase in 3.4, “technically substantiated”. Using the terminology “more likely” seems to invalidate any conditions that are “technically substantiated”, allowing nothing less than the instantaneous complete destruction of multiple substations. This is impractical.

The NERC report on CIP-014 noted that NERC finds that the inconsistent approach to performing the risk assessment is largely due to a lack of specificity in the requirement language as to the nature and parameters of the risk assessment. Is it more likely all systems are inoperable or more likely just a few systems are inoperable? Several scenarios could exist which seems subjective and will still result in inconsistent approaches.

Please add examples of various scenarios to address these issues.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The draft standard allows Transmission Owners to use actual clearing times, which addresses the greater specificity requested in the comment. Clearing times are often specific to individual Transmission Owners so the DT believes it would be inappropriate to prescribe them in this standard.

Requirement R3.4 has been modified to address the comments in paragraphs 2 through 4

The DT has reduced the distance requirement in Requirement R2 which addresses this comment.

“More likely” has been removed from the draft standard.

The DT believes they have added adequate specificity to address the directives of the SAR.

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	No
Document Name	

Comment

A 36month frequency of this standard has a shorter time cycle than some entities broader system studies which determine cascading, uncontrolled separations etc… in many regions the RC or ISOs perform these studies and provide results to the TO for use in CIP-014. These entities must also have to adjust their study cycle (which is very onerous) OR suggestion is to add a statement in the standard that allows the TO use their discretion with RC to use the most recent studies available.

Likes 0	

Dislikes 0	
Response	
Thank you for the comment. The SAR requires the DT to align the different timelines and study cycles used in CIP-014-3. The 36 month frequency is longer than the 30 month frequency used in CIP-014-3.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	No
Document Name	
Comment	
Black Hills Corporation agrees with EEI's suggestion to remove the word "proximity" from R3 to avoid using a term that is undefined in R2. Black Hills Corporation also agrees with EEI's comment that R3 Part 3.1.1 duplicates the concepts in R3 Part 3.1. Therefore, R3 Part 3.1.1 is not needed.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to EEI's comments.	
John Pearson - ISO New England, Inc. - 2	
Answer	No
Document Name	
Comment	
R3.3 should specify a three phase Fault to ensure consistency in performing studies. Also, see response to Question 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The DT believes that simulation of a fault is a reasonable assumption for possible events that could impact a single Transmission station or Transmission substation, and for events that could simultaneously impact multiple Transmission stations or Transmission substations. The DT does not believe that specification of fault type (e.g., 3-phase faults or single-line-to-ground faults) was mandated by the SAR, and furthermore believes that such a specification is a) too prescriptive and b) potentially creates scenarios that do not match up with plausible threat vectors assessed and managed by corporate security personnel complying with CIP-014 Requirements R7 – R10. The DT furthermore believes that simulation of a no-fault event is not a reasonable assumption for physical attacks under CIP-014. While plausible, no-fault events are not in keeping with the direction of the SAR.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	

Comment

ITC proposes the following revisions for consideration:

The term “proximity” is not used in Requirement R2. ITC suggests removing it from Requirement R3 and its sub parts.

R3. Each Transmission Owner shall have a documented risk assessment methodology, including criteria for steady-state and dynamic simulations, for evaluating the loss due to a physical attack of each applicable Transmission station(s) and Transmission substation(s) documented in Requirement R1 and Transmission substation(s) or Transmission station(s) determined to be in proximity per Requirement R2. The methodology shall include, at a minimum, the following:

Requirement R3, Parts 3.1 and 3.1.1 include duplicative concepts that could lead to confusion implementing and/or documenting the requirement parts. As an example, Requirement R3 requires the Transmission Owner to have a documented risk assessment methodology, including criteria for steady-state and dynamic simulations. Requirement R3, Part 3.1 requires the methodology to include technically supported thresholds and rationale, and Part 3.1.1 restates the requirement for the technical rationale to include steady-state and dynamic system response to events. ITC suggests consolidating the requirement parts as written below:

{C}a. {C}Thresholds for determining the amount of acceptable load loss, the amount of acceptable generation loss, and post-event response recognized as resulting in instability, uncontrolled separation, or Cascading within an Interconnection. The technical rationale shall include:

{C} i. Steady-state and dynamic system response to events that could lead to load loss, generation loss, and other unacceptable post-event response

Requirement R3.2 ITC recommends that the phrase (that are more likely to contribute to) be deleted from the requirement. This is subjective and could lead to violations if your ERO disagreed with what you determined was not a more likely scenario as appropriate for your studies.

Requirement R3, Part 3.2.2 goes beyond the scope of what is documented in the SAR by requiring additional steady-state analysis after the steady-state and dynamic simulations show acceptable system response. The SAR specifically states that “[t]o ensure that a station is effectively identified as non-critical, registered entities need to have performed both steady-state and dynamic studies” but does not go into further detail about performing another steady-state analysis that includes any tripped Elements from the dynamic simulations. We recommend striking Requirement R3, Part 3.2.2.

Requirement R3, Part 3.3 could be further clarified and reference to proximity should be removed in favor the reference to R2, we suggest the following language:

3.3 For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, analysis shall include a Fault **in the simulation** at both the applicable Transmission station or Transmission substation and **at** each associated Transmission station or Transmission substation identified in accordance with Requirement R2 as being in proximity to the applicable Transmission station or Transmission substation.

Requirement R3, Part 3.4 is not clear as written. If the intention of the drafting team is for 3.4 to require fault simulations that assume the loss of communication and Protection System at all of the Transmission station(s) or Transmission substation(s) studied under Requirements R3, Parts 3.2 and 3.3 simultaneously, we suggest the following revision:

3.4. Fault simulations that assume the loss of communication and Protection System at **all of** the Transmission station(s) or Transmission substation(s) studied under Requirement R3, Parts 3.2 and 3.3. The TO shall identify the clearing times utilized for the required studies.

ITC recommends that both 3.4.1 and 3.4.2 are too prescriptive. An estimate of clearing times is typically used for dynamics studies to alleviate the administrative burden of identifying the expected clearing times for each specific scenario being analyzed.

ITC appreciates that drafting team’s revision to Requirement R3, Part 3.4.2 to provide flexibility in the clearing times used, however, by stating “Actual or more conservative” entities will still need to calculate the actual clearing times in order to validate that the estimates used were more conservative. We suggest the following if the DT believes this is essential:

3.4.2. Actual or more conservative estimates of clearing times shall be used.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

The use of “proximity” in requirement R3.3 is not intended to define a term but is used only in a descriptive sense.

Requirement R3.1.1 has been removed from the draft standard.

Requirement R3.2 has been modified and “more likely” has been removed.

Requirement R3.2.2 has been removed from the draft standard.

Modifications and clarifications have been made to Requirements R3.3 and R3.4. Please see draft standard.

The DT believes that “more” is a necessary clarifying term in Requirement R3.4.2. Please see the Technical Rationale for justification.

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1

Answer	No
Document Name	

Comment

NIPSCO agrees with EEI comments:

“The term “proximity” is not used in Requirement R2. EEI suggests removing it from Requirement R3 and its sub parts.

R3. Each Transmission Owner shall have a documented risk assessment methodology, including criteria for steady-state and dynamic simulations, for evaluating the loss due to a physical attack of each

applicable Transmission station(s) and Transmission substation(s) documented in Requirement R1 and Transmission substation(s) or Transmission station(s) determined per Requirement R2. The methodology shall include, at a minimum, the following:

Requirement R3, Parts 3.1 and 3.1.1 include duplicative concepts that could lead to confusion implementing and/or documenting the requirement parts. As an example, Requirement R3 requires the Transmission Owner to have a documented risk assessment methodology, including criteria for steady-state and dynamic simulations. Requirement R3, Part 3.1 requires the methodology to include technically supported thresholds and rationale, and Part 3.1.1 restates the requirement for the technical rationale to include steady-state and dynamic system response to events. EEI suggests consolidating the requirement parts as written below:

3.1 Technically supported thresholds and rationale for determining the amount of acceptable load loss, the amount of acceptable generation loss post-event response, and any additional considerations recognized as resulting in instability, uncontrolled separation, or Cascading within an Interconnection.

Requirement R3, Part 3.2.2 goes beyond the scope of what is documented in the SAR by requiring additional steady-state analysis after the steady-state and dynamic simulations show acceptable system response. The SAR specifically states that “[t]o ensure that a station is effectively identified as non-critical, registered entities need to have performed both steady-state and dynamic studies” but does not go into further detail about performing another steady-state analysis that includes any tripped Elements from the dynamic simulations. We suggest striking Requirement R3, Part 3.2.2.

Requirement R3, Part 3.3 could be further clarified and reference to proximity should be removed in favor the reference to R2, we suggest the following language:

3.3 For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, analysis shall include a Fault ***in the simulation*** *at the applicable Transmission station or Transmission substation and* ***then at*** *each Transmission station or Transmission substation identified in accordance with Requirement R2.*

Requirement R3, Part 3.4 is not clear as written. If the intention of the drafting team is for 3.4 to require fault simulations that assume the loss of communication and Protection System at all of the Transmission station(s) or Transmission substation(s) studied under Requirements R3, Parts 3.2 and 3.3 simultaneously, we suggest the following revision:

3.4. Fault simulations that assume the loss of communication and Protection System at ***all of*** *the Transmission station(s) or Transmission substation(s) studied under Requirement R3, Parts 3.2 and 3.3.*

EEI appreciates that drafting team's revision to Requirement R3, Part 3.4.2 to provide flexibility in the clearing times used, however, by stating "Actual or more conservative" entities will still need to calculate the actual clearing times in order to validate that the estimates are more conservative. We suggest:

3.4.2. Actual or conservative estimates of clearing times shall be used unless otherwise technically substantiated."

NIPSCO agrees with NV Energy comments:

The open-ended nature of "physical attack" results in very different interpretations of severity and subsequent protection system fault modeling results. This could be especially true depending on substation locations and inherent risk differences throughout the country. Clarify if the decisions to the questions above are left up to each company and their own assessment methodology?

Add examples to the rationale to address the various scenarios involving a substation under study and any adjacent substations meeting the ½ mile proximity. For example: Are they faulted simultaneously or individually with or without the same damage or inoperability? Are these questions up to each individual assessment methodology?

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the DT's response to EEI's comments.

The Drafting Team has added clarity to Requirement R3 that addresses the NV Energy comments.

Kelley Sargent - Puget Sound Energy, Inc. - 3

Answer	No
Document Name	

Comment

The standard needs to be prescriptive on amount of load loss/generation loss that may impact an Interconnection (i.e. result in instability, uncontrolled separation or Cascading within an Interconnection). Sometimes loss of large spot loads (data centers etc.) may not represent a general wide area outage in an interconnection; and number of customers or area distribution substations may provide better representation of a wide area outage/blackout.

Likes 0	
Dislikes 0	

Response	
The intent of the standard is to capture those situations where the loss of load or generation could result in instability, uncontrolled separation, or Cascading within an Interconnection. These load and generation thresholds may vary between Interconnections and thus are difficult to prescribe.	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	No
Document Name	
Comment	
See comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to EEI's comments.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	No
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to EEI's comments.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
Salt River Project (SRP) agrees with EEI's suggestion to remove the word "proximity" from R3 to avoid using a term that is undefined in R2, and that R3 Part 3.1.1 duplicates the concepts in R3 Part 3.1.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to EEI's comments.	

Stefanie Burke - Portland General Electric Co. - 6	
Answer	No
Document Name	
Comment	
PGE supports the comments of EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the DT's response to EEI's comments.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
The standard clearly defines the expectation of what events to perform for steady state and dynamic simulations.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
FirstEnergy has no concerns with the proposed R3 for CIP-014-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and support.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes

Document Name	
Comment	

LG&E/KU supports the modifications in Requirement R3, but notes three non-substantive corrections. First, Requirement R3 Part 3.1.1 is redundant with Part 3.1 and could be removed. Second, "Protection System" in Requirement R3 Part 3.4 should be "Protection Systems". Third, Requirement R3 Part 3.4 incorrectly states "… studied under Requirement R3, Parts 3.2 and 3.3." It should only reference Part 3.3 since all Faults are now described in the same Part.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments and support. Requirement R3, Part 3.1.1 has been removed. "Protection System" has been corrected as suggested. Please see revised Standard on your third comment as the sub-Requirements have been reorganized.

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	
Comment	

Was the intent to have the responsible entity establish their own "acceptable load loss." In other cases, it is up to the BA, RC, or RP to determine the Facility's acceptable load loss.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments and support. The DT has drafted the language to require Transmission Owners to have criteria for acceptable load loss in their methodologies. It is a reasonable assumption that in many cases these criteria may be established by the Transmission Owners respected BA, RC, or RP. Whether determined by these or other entities, there should be technical justifications for the criteria.

Daniel Gacek - Exelon - 1

Answer	Yes
Document Name	
Comment	

Exelon agrees R3 addresses issues identified in the SAR, however, the term "Fault" is overly broad in the Draft 2 revision and does not provide the clarity directed by the SAR. Exelon prefers the Draft 1 version of R3 with the faults specified as at the highest voltage level, and with the fault magnitudes provided as specific fault types. The Draft 1 version of R3 provided criteria that created the "consistency of approach" the SAR is intended to achieve.

Submitted on behalf of Exelon - Segments 1 & 3

Likes 0	

Dislikes 0	

Response

Thank you for your comments and support. Due to the comments received from the industry from the previous ballot, the DT has removed the specificity regarding the type of Fault to apply.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	Yes
Document Name	

Comment

NV Energy appreciates moving most of the granular specifications of R3.1 to the Technical Rationale. NV Energy would prefer that these were also removed from the Technical Rationale due to concern that an auditor may solely rely upon the Technical Rationale in interpreting R3.1 That could lead to circumstances in which an entity is held to compliance with the Technical Rationale rather than the actual language the of requirement."

Requirement R3.2 states "Steady-state and dynamic simulations shall be performed under System conditions that are **more likely** to contribute to instability, uncontrolled separation, or Cascading within an Interconnection". Please reconcile the statement in 3.2 how "more likely to contribute to instability, uncontrolled separation, or Cascading" clarifies "technically substantiated" in requirement 3.4. Using terminology such as "more likely" seems to remove the possibility to technically substantiate anything less than complete destruction of multiple substations. This seems impractical.

The NERC report on CIP-014 noted that NERC finds that the inconsistent approach to performing the risk assessment is largely due to a lack of specificity in the requirement language as to the nature and parameters of the risk assessment. For example, is the protection system "rendered inoperable" where no substation protection system would operate or instead just damaged where the secondary protection is inoperable but the primary still operates for the substation? Is it more likely all systems are inoperable or more likely just a few systems are inoperable? A huge number of scenarios could exist which seems very subjective and will still result in inconsistent approaches. Clarify if the decisions to these questions are left up to each company and their own assessment methodology?

Note: remove or damaged due to being redundant due to "rendered inoperable"

If an assessment methodology allows for pilot schemes to trip high speed without communications such as DCB lack of blocking signal or DCUB unblocking schemes when the guard signal is lost during the trip window allowing a highspeed trip, is this technically substantiated? Add some discussion in the technical rationale regarding loss of communications for protection schemes.

Likes 0	
Dislikes 0	

Response

Thank you for your comments and support.

The DT understands your concern with the auditor's approach. However, the SAR calls out that the risk assessment methods for studying and methods should account for dynamic studies. The DT believes that this language belongs to the Standard, not the Technical Rationale Document.

The DT has removed "more likely" from the current draft, and there is no longer a discrepancy between Requirement R3, Part 3.2 and Part 3.4.

Clarification on “rendered inoperable or damaged” is given in Requirement R3, Part 3.4.	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
The new R3 is acceptable, but we have a couple remaining concerns: I'm still not sure how to determine "technically supported thresholds" for gen and load loss, outside of what results in " instability, uncontrolled separation, or Cascading." Are these intended to be seperate determinations? In reference to 3.4 specifically, I appreciate the requirement being less prescriptive about how we run the study, but we have experienced disagreement with regulators about what type of physical attack we are supposed to simulating (i.e. "smoking crater" vs something more realistic). It would be nice to have some guidance here to help clear up the ambiguity so that we can choose the appropriate contingencies to run.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and support. The DT has removed the phrase "technically supported thresholds", however, it is prudent for each Transmission Owner to work with its respective Regional Entities to establish thresholds that, if exceeded, would be expected to cause instability, uncontrolled separation, or Cascading within an interconnection. Regarding the type of physical attack, the DT believes that this issue is adequately addressed in the modeling requirements in Requirement R3.	
Jennifer Mcnally - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy supports the revisions to R3 from Draft 1. For additional clarity, we suggest the following language for R3.3 “For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, analysis shall include a Fault **in the simulation** at the applicable Transmission station or Transmission substation and **then at** each Transmission station or Transmission substation identified in accordance with Requirement R2 as being in proximity to the applicable Transmission station or Transmission substation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and support. Please see revised language in the latest Requirement R3, Part 3.3, which has now adequately addresses this issue.	
Ellese Murphy - Ellese Murphy On Behalf of: Katherine Street, Duke Energy , 5, 6, 1, 1; - Ellese Murphy	
Answer	Yes

Document Name	
Comment	

Duke Energy supports the revisions to R3 from Draft 1. For additional clarity, we suggest the following language for R3.3 "For each applicable Transmission station or Transmission substation listed in accordance with Requirement R1, analysis shall include a Fault **in the simulation** at the applicable Transmission station or Transmission substation and **then at** each Transmission station or Transmission substation identified in accordance with Requirement R2 as being in proximity to the applicable Transmission station or Transmission substation.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments and support. The drafting team has modified Requirement R3, Part 3.3 to include "specification for Fault simulations" and "for each applicable Transmission station or Transmission substation".

Matthew Nicklin - Southern Illinois Power Cooperative - 1,3,5 - SERC

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.

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

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.

Sean Steffensen - IDACORP - Idaho Power Company - 1

Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE is concerned the proposed Requirement Part 3.3 language does not specify the type of fault conditions (line-to-ground fault or three-phase fault) criteria that needs to be studied. Texas RE is also concerned with the use of the NERC Glossary definition of Fault, as it does not include line-to-ground faults or three-phase faults. Not defining the type of fault leaves it open for inconsistent applicability by the Transmission Owners. The drafting team should consider specifying the fault type to be used in the simulations to capture the highest risk conditions. At minimum, 'Fault' should not be	

capitalized, but a clear definition of the required “fault” conditions to be studied should be developed in the standard itself to avoid inconsistency in the compliance and subsequent auditing process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team intends to include any event occurring on an electric system. No specific fault type needs to be called out.	

4. Do you agree with the modifications made in CIP-014-4 with new Requirement R4 to address the issues identified in the SAR?

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

Answer	No
Document Name	

Comment

Salt River Project (SRP) supports Duke Energy's comment to clarify “owned by multiple Transmission Owners” and clarification on having elements at a station or substation with differing ownership and whether that would make or not make a station or substation jointly owned.

Likes 0	
Dislikes 0	

Response

Thank you for the comments. Please see responses to Duke Energy’s comment. The drafting team has edited R4 for the third draft to provide additional clarification on the jointly owned issue, which was listed as part of the project work scope of the SAR.

Ellese Murphy - Ellese Murphy On Behalf of: Katherine Street, Duke Energy , 5, 6, 1, 1; - Ellese Murphy

Answer	No
Document Name	

Comment

Duke Energy requests additional clarification on “owned by multiple Transmission Owners” and requests that the team clarify that merely having elements at a station or substation with differing ownership would not make a station or substation jointly owned. If the Drafting team does intend thatelements from another Transmission Owner could classify a station or substation as “owned by multiple Transmission Owners”, what is the mechanism to ensure coordination occurs? Particularly if the visiting Transmission Owner does not have compliance in scope for CIP-014.

Likes 0	
Dislikes 0	

Response

Thank you for the comments. The drafting team edited R4 for the third draft to provide additional clarification on the jointly owned issue, which was listed as part of the project work scope of the SAR. Regarding the ensuring of coordination, the DT asserts that NERC Reliability Standards are not generally designed to guarantee this. For example, PRC-006-5 Requirement R5 requires coordination between multiple Planning Coordinators, with no mechanism in place to ensure such coordination will occur.

Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott

Answer	No
Document Name	

Comment

The inclusion of R4 is not identified as needed in the NERC CIP-014 Report nor in the SAR for the project. The inclusion of this requirement leads to a number of questions that have not been clarified. If For an entity that has a station with multiple voltage areas including some that are not applicable to CIP-014, how would an entity determine if this would be considered a joint station. If the second TO only has facilities that would not be applicable to CIP-014 within the substation, would they have to identify joint responsibilities for these sites.

If this requirement is retained, ITC believes it would be prudent to only consider the CIP-014 applicable voltages in the station to determine if it would be a joint station.

Likes 0	
Dislikes 0	

Response

Thank you for the comments. The drafting team edited R4 for the third draft to provide additional clarification on the “jointly owned” and “applicability” issues, which was listed as part of the project work scope of the SAR.

Jennifer Mcnally - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No
Document Name	

Comment

Duke Energy requests additional clarification on “owned by multiple Transmission Owners” and requests that the team clarify that merely having elements at a station or substation with differing ownership would not make a station or substation jointly owned. If the Drafting team does intend that elements from another Transmission Owner could classify a station or substation as “owned by multiple Transmission Owners”, what is the mechanism to ensure coordination occurs? Particularly if the visiting Transmission Owner does not have compliance in scope for CIP-014.

Likes 0	
Dislikes 0	

Response

Thank you for the comments. The drafting team edited R4 for the third draft to provide additional clarification on the jointly owned issue, which was listed as part of the project work scope of the SAR. Regarding the ensuring of coordination, the DT asserts that NERC Reliability Standards are not generally designed to guarantee this. For example, PRC-006-5 Requirement R5 requires coordination between multiple Planning Coordinators, which involves effort on all involved registered entities to jointly discuss and develop the UFLS program design. Evaluating whether this coordination took place as specified by Requirement R5 would be accomplished by NERC and the Regional Entities through the Compliance Monitoring and Enforcement processes (e.g. Compliance Audit, Spot Check, Self-Report, etc.).

John Pearson - ISO New England, Inc. - 2

Answer	No
Document Name	

Comment

R4 should reference both R1 and R2. The modifed language is shown below:

Each Transmission Owner with applicable Transmission station(s) and Transmission substation(s) per Requirement R1 and R2 owned by multiple Transmission Owners shall coordinate with those Transmission Owners to determine and document their individual and joint responsibilities for performing any required risk assessments per Requirement R5. *[VRF: Medium; Time-Horizon: Operations Planning, Long-term Planning]*

Likes 0	
Dislikes 0	
Response	
Thank you for the comments. The DT believes that existing R1 reference is sufficient, as it keeps R4 properly focused solely on Transmission Owners with applicability to CIP-014.	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	No
Document Name	
Comment	
This section refers to Transmission owners coordinating with other transmission owners. Further clarification is needed to address how TO should coordinate activities with a GO which are both in 'proximity' to each other. Which standards does a GO need to follow and how can this be enforced by a TO.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. R4 applies solely to Transmission Owners. Proximity of Transmission Owners to Generator Owners thus has no CIP-014 applicability and furthermore is outside the scope of the SAR.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
Please provide additional details on the expected outcome of joint risk assessments. Is agreement of the results of the risk assessments between the entities required?	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. Regarding agreement of the results, the drafting team responds similarly to comments on a guarantee of coordination. No guarantee that coordination will occur without difficulty or that results will agree is possible. To the extent that agreement can be achieved, this is of course desirable. In the event that it cannot, each Transmission Owner should be able to technically justify its results using its own evidence.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	

SERC appreciates the ongoing efforts to refine the CIP-014 Risk Assessment portion of the standard. SERC believes the coordination efforts in R4 should include R3 as well as R5, so that consistency and clarity in study results between multiple entity owners is maintained. In the case where all owners share the same R3 and R4 thresholds (such as in an RTO/ISO), only an acknowledgement of such would be needed to affirm consistency.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. Requirement R4 has been modified accordingly.	
Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	No
Document Name	
Comment	
As written, the revised R4 appears to indicate that each TO that owns a part of a Transmission station or a Transmission substation identified pursuant to the assessment required in R1 should coordinate with those other TOs to determine their "individual and joint responsibilities" for performing any required risk assessments. It appears that the subject TOs could agree that each TO can prepare its own risk assessment of the subject station. If that is not what the SDT intended, then R4 needs to be clarified to affirmatively state more clearly what is intended. It also appears that R4 does not require that each of the TOs that owns a part of a Transmission station or a Transmission substation must use the same methodology in preparing its required risk assessment. Again, if that is not what the SDT intended, then R4 needs to be clarified to make any methodological requirements clear. Fundamentally, there are two inherent assumptions in the revised R4: (1) that it will always be possible for a TO to coordinate with all other TOs owning a Transmission station or a Transmission substation; and (2) that those TOs will always be able to agree on the responsibilities for preparing any required risk assessments. Unfortunately, that will likely not always be the case. To address this possibility, R4 should be revised to allow a TO to perform its own required risk assessment if the TOs cannot agree on the responsibilities for performing the required risk assessments.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. The DT affirms that each TO can prepare its own risk assessment of the subject station, and that each may have its own methodology. Regarding difficulties in agreement/coordination between TOs, see earlier responses to Duke Energy and Nebraska Public Power District comments. To the extent that agreement can be achieved, this is of course desirable. In the event that it cannot, each Transmission Owner must be able to technically justify its results using its own evidence. In the extremely unlikely scenario that coordination is attempted but fails to occur, evidence of the attempt at coordination will suffice as evidence of coordination.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	

Is the 36-month periodicity with regard to the coordination, the risk assessment, or both? We suggest adding that only changes in responsibilities of Joint substation or stations should be documented once every 36 months or attestation that no changes occurred in responsibilities during the 36-month period. At scale, these substation and stations can be an administrative burden due to the number of agreements an entity may have, and an overarching document may be a better solution for management of these agreements. We are unsure of the intended goal or end value of the requirement and would like clarification Does the outcome of the risk assessment need to be agreed to by both parties of a Joint substation or station? Additional clarification on what is expected for the outcome of the coordinated risk assessment should be clarified.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. Coordination must take place such that a risk assessment is completed at least once every 36 calendar months. Regarding coordination and agreement, see previous responses to Duke Energy and Nebraska Public Power District comments.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
The requirement is appropriate in the context that the referenced risk assessment is from a physical security perspective and not a transmission planning analysis perspective. Should the intent of this comment be applicable to physical security and not a transmission planning analysis, then our answer would be yes.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. The SAR supports coordination between multiple Transmission Owners of a station or substation, and specifically in the performance of transmission planning analyses. While CIP-014 is officially a physical security standard, of a practical nature it is a planning standard, as evidenced by the fact that the Time Horizon stated for all Requirements is Near-Term Planning.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	No
Document Name	
Comment	
Is the 36-month periodicity with regard to the coordination, the risk assessment, or both? We suggest adding that only changes in responsibilities of Joint substation or stations should be documented once every 36 months or attestation that no changes occurred in responsibilities during the 36-month period. At scale, these substation and stations can be an administrative burden due to the number of agreements an entity may have, and an overarching document may be a better solution for management of these agreements. We are unsure of the intended goal or end value of the requirement and would like clarification	

Does the outcome of the risk assessment need to be agreed to by both parties of a Joint substation or station? Additional clarification on what is expected for the outcome of the coordinated risk assessment should be clarified.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. Coordination must take place such that a risk assessment is completed at least once every 36 calendar months. Regarding coordination and agreement, see previous responses to Duke Energy and Nebraska Public Power District comments.	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	No
Document Name	
Comment	
It is recommended to add R2 (in addition to R1) to the language of R4 so as to clarify that coordination for "Transmission station(s) and Transmission substation(s), irrespective of ownership, within ½ mile of an applicable Transmission station or Transmission substation documented in Requirement R1" may be required - for situations where stations identified under R2 have different ownership.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. The DT believes that existing R1 reference is sufficient, as it keeps R4 properly focused solely on Transmission Owners with applicability to CIP-014.	
Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis	
Answer	No
Document Name	
Comment	
MPC strongly disagrees with the use of a 36-month timeframe for utilities who have not previously identified stations or substations as critical for the same reasons specified in our comments for Question 5.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. The DT was directed in the SAR to "correct any discrepancies between the study period, frequency of study, and the base case(s) a Transmission Owner uses." The DT clarified and simplified the timeframes, while recognizing the challenges in correcting these discrepancies (24-months-out modeling, 30 and 60 months study frequency) to all entities' satisfaction.	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	No

Document Name	
Comment	

BPA finds the current wording of R4 does not address the inclusions in R2 sub-requirements 2.1 and 2.2.

Likes 0	
Dislikes 0	

Response

Thank you for the comments. The Requirement R4 is associated with Requirements R1, R3, and R5, not Requirement R2. Furthermore, sub-Requirements Parts 2.1 & 2.2 have been removed from this version.

Jeffrey Streifling - NB Power Corporation - 1

Answer	No
Document Name	

Comment

Is the 36-month periodicity with regard to the coordination, the risk assessment, or both? We suggest adding that only changes in responsibilities of Joint substation or stations should be documented once every 36 months or attestation that no changes occurred in responsibilities during the 36-month period. At scale, these substation and stations can be an administrative burden due to the number of agreements an entity may have, and an overarching document may be a better solution for management of these agreements. We are unsure of the intended goal or end value of the requirement and would like clarification

Does the outcome of the risk assessment need to be agreed to by both parties of a Joint substation or station? Additional clarification on what is expected for the outcome of the coordinated risk assessment should be clarified.

Likes 0	
Dislikes 0	

Response

Thank you for the comments. Coordination must take place such that a risk assessment is completed at least once every 36 calendar months. Regarding coordination and agreement, see previous responses to Duke Energy and Nebraska Public Power District comments.

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	No
Document Name	

Comment

Is the 36-month periodicity with regard to the coordination, the risk assessment, or both? We suggest adding that only changes in responsibilities of Joint substation or stations should be documented once every 36 months or attestation that no changes occurred in responsibilities during the 36-month period. At scale, these substation and stations can be an administrative burden due to the number of agreements an entity may have, and an overarching document may be a better solution for management of these agreements. We are unsure of the intended goal or end value of the requirement and would like clarification

Does the outcome of the risk assessment need to be agreed to by both parties of a Joint substation or station? Additional clarification on what is expected for the outcome of the coordinated risk assessment should be clarified.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. Coordination must take place such that a risk assessment is completed at least once every 36 calendar months. Regarding coordination and agreement, see previous responses to Duke Energy and Nebraska Public Power District comments.	
Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	
Transmission Owners who are identified in R1 do not have to be coordinate if they do not have facilities as identified in Attachment 1. The reference to R5 should be deleted and language such as "...their individual and joint responsibilities for performing any required risk assessments per this standard." Has the drafting team considered where two substations are in close proximity together and where a single event can affect both substations: however, one is owned by an applicable entity under R1, and the other is not?	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. Since R5 is the primary Requirement for risk assessment performance, linking it to R4 is appropriate. Regarding the proximity comment, see responses to comments in the Q2/R2 section.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments.	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	

Comment	
See comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments.	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	Yes
Document Name	
Comment	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments. Please see responses to the EEI's comments.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy appreciates the removal of a periodicity requirement.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments and support.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI agrees with the modifications made to CIP-014-04 Requirement R4.

Likes 0	
Dislikes 0	

Response

Thank you for the comments and support.

Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker

Answer	Yes
Document Name	

Comment

Cleco agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

Thank you for the comments and support. Please see the responses provided to EEI’s comments.

Matt Carden - Southern Company - Southern Company Services, Inc. - 1

Answer	Yes
Document Name	

Comment

Southern Company agrees with the modifications.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

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

Answer	Yes
Document Name	

Comment

FirstEnergy has no concerns with the proposed R4 for CIP-014-4.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Leshel Hutchings - AEP - 3

Answer	Yes
Document Name	

Comment

None

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Stefanie Burke - Portland General Electric Co. - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Amy Wilke - American Transmission Company, LLC - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Teresa Krabe - Lower Colorado River Authority - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Richard Vendetti - NextEra Energy - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

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

Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carver Powers - Utility Services, Inc. - 4	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response

Thank you for your support.

James Keele - Entergy - 3

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Matthew Nicklin - Southern Illinois Power Cooperative - 1,3,5 - SERC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Tamarra Hardie - Tamarra Hardie On Behalf of: Diane E Landry, Public Utility District No. 1 of Chelan County, 3, 5, 1, 6; - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Mark Flanary - Midwest Reliability Organization - 10

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

5. Do you agree with the modifications made in CIP-014-4 with adding Requirement R5 to address the issues identified in the SAR?

Kevin Conway - Western Power Pool - 4	
Answer	No
Document Name	
Comment	

This goes back to R1 where ALL TOPs should be required to meet R1 (every 36 months), and only those who have Facilities that meet Attachment 1 will be responsible for meeting compliance to the rest of the Standard.

As written, entities may find they are exempt from the proposed standard initially, and there is no requirement for them to re-evaluate their applicability.

Likes 0	
Dislikes 0	
Response	

Thank you for the comment. Please see the DT's Q1 response.

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	No
Document Name	
Comment	

We suggest adding language about required actions where a TO designate another entity's Control Center in part 5.2. for instance, coordination between the entities and information security.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. This has been addressed in Requirement R7.

Jeffrey Streifling - NB Power Corporation - 1	
Answer	No
Document Name	
Comment	

We suggest adding language about required actions where a TO designate another entity's Control Center in part 5.2. for instance, coordination between the entities and information security.

Likes 0	

Dislikes 0	
Response	
Thank you for your comment. This has been addressed in Requirement R7.	
Tamarra Hardie - Tamarra Hardie On Behalf of: Diane E Landry, Public Utility District No. 1 of Chelan County, 3, 5, 1, 6; - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	No
Document Name	
Comment	
It is recommended to also update the R5 VRF to reference the Near-Term Transmission Planning Horizon instead of the Long-Term Transmission Planning Horizon. The R5 VRF Time Horizon still states it applies to 'Long-term Planning Horizon', whereas the NERC Glossary of Terms defines the 'Near-Term Planning Horizon' as the window covering year 1 through 5. This requirement references 'at least once every 36 calendar months', so it is recommended that the R5 VRF Time Horizon language is updated to reference the 'Near-Term Transmission Planning Horizon'. Otherwise, the changes are generally good.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. NERC Glossary of Terms is different from NERC Time Horizons. NERC Time Horizons define "Long-term Planning" as "a planning horizon of one year or longer". This document is located on NERC public site: Document Portrait.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	No
Document Name	
Comment	
Was "previously" meant to be struck in R5.1? The intent of this section was believed to be that if a station was previously found to be impactful, it does not have to be restudied; is that not the case? Requirement R5.3 should be added stating something similar to "Multiple Transmission Owners of stations within proximity as determined in R2 shall share the results of their analyses related to the stations within proximity with all the other Transmission Owners of the stations within proximity."	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The Drafting Team has added "previously" back to section R5.1. Thank you for your suggestion on Requirement R5.3. The drafting team did discuss this and believes the existing standard language does not preclude the TO from sharing their results with proximate substation owners.	
Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis	

Answer	No
Document Name	

Comment
MPC strongly disagrees with the use of a 36-month timeframe for utilities who have not previously identified any substations as critical as it is both outside the scope of the SAR and will lead to increased study costs with little or no benefit to BES reliability. During the 6/7/24 NERC webinar for Draft 1, the SDT stated the goal of changing the risk assessment timeframe to 36 months was to align the CIP-014 risk assessment with the model build timeframe of another standard. Later, MPC requested clarification on which standard the SDT is aligning with during the 10/17/24 industry webinar, and the SDT indicated it aligns with the 12-month timeframe of the TPL-001 standard. The CIP-014 analysis does not depend on the models built for TPL-001, and MPC believes changing the CIP-014 study timing to align with the TPL-001 model build process provides no additional reliability benefit to the BES for entities that have not identified critical stations/substations. Furthermore, the existing 60-month timeframe can also align with the 12-month model build timeframe of the TPL-001 standard. Stations and substations planned to be in service within 24 months of the CIP-014 risk assessment are already required to be included under R1 of CIP-014-3 (or within 36 months with proposed CIP-014-4 R1), which suggests that decreasing the risk assessment timeframe from 60 months to 36 months is very unlikely to identify stations or substations that would not already be identified under CIP-014 R1. Moreover, the very slow pace of construction of new electrical infrastructure due to increased equipment lead times, supply chain constraints, and labor shortages makes it highly unlikely that modifications to an existing non-critical Transmission station or substation could be planned, designed, and constructed such that it would be elevated to a critical station/substation within 36 months. It is equally unlikely that a newly constructed CIP-014 critical substation would be completed within this timeframe. For utilities who have previously not identified substations as critical, reducing the risk assessment timeframe from 60 months to 36 months will result in increased costs due to more frequent risk assessments, with the more frequent assessments having no reliability benefit as they have little to no chance of identifying more Transmission stations or substations as CIP-014 critical that would not already have been under the CIP-014-3 Standard.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The DT did look into this and believes that the current version meets the work scope of the SAR. Requirement R1 is revised to ensure that each Transmission Owner establishes a list of applicable Transmission station(s) or Transmission substation(s) in accordance with Attachment 1. Aligning the 36 calendar months look ahead in Requirement R1 with the 36 calendar month risk assessment cycle ensures that system topology of the cases used to assess applicability is consistent with the system topology in the risk assessment models.

Gary Trezza - Long Island Power Authority - 1 - NPCC

Answer	No
Document Name	

Comment

Was “previously” meant to be struck in R5.1? The intent of this section was believed to be that if a station was previously found to be impactful, it does not have to be restudied; is that not the case?

It is recommended that a new “Requirement R5.3” be added stating something similar to “Multiple Transmission Owners of stations within proximity as determined in R2 shall share the results of their analyses related to the stations within proximity with all the other Transmission Owners of the stations within proximity.”

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The Drafting Team has added “previously” back to section R5.1. Thank you for your suggestion on Requirement R5.3. The drafting team did discuss this and believe the existing standard language does not preclude the TO from sharing their results with proximate substation owners.

Matt Carden - Southern Company - Southern Company Services, Inc. - 1

Answer	No
Document Name	

Comment

Southern Company agrees with the intent of this requirement. However, as it is presently written, the requirement only applies to jointly owned Transmission station(s) and Transmission substation(s). Consider the below modifications:

R5. At least once every 36 calendar months, each Transmission Owner shall perform a risk assessment to identify Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection, using the methodology established in Requirement R3 including any Transmission station(s) and Transmission substation(s) identified in accordance with documentation established per Requirements R1, R2, and R4.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the revised Requirement R5. The drafting team made extensive modifications to clarify that a risk assessment shall be performed at least once every 36 calendar months for all of the Transmission station(s) and Transmission substation(s) identified in Requirements R1, R2 and R4, using the methodology established in Requirement R3, as well as identification of associated primary control centers.

Jessica Cordero - Unisource - Tucson Electric Power Co. - 1

Answer	No
Document Name	

Comment

Does not provide an option for de-classification of a Transmission Substation from critical to non-critical. Additional projects could provide more resiliency to the BES that could result in a substation no longer causing instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged as a result of a physical attack.

Language R5.1 does not provide additional value and is confusing.

How many assessments can be skipped for a specific site identified that causes instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged as a result of a physical attack? The current language implies that a site that is initially identified as causing instability, uncontrolled separation, or Cascading within an Interconnection never needs to be re-evaluated in any future risk assessments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see revised language. The drafting team made extensive modifications to better lay out the intent of the assessment as well as identification of associated primary control centers.

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

Answer	No
Document Name	

Comment

We suggest adding language about required actions where a TO designate another entity's Control Center in part 5.2. for instance, coordination between the entities and information security.

Was "previously" meant to be struck in R5.1? The intent of this section was believed to be that if a station was previously found to be impactful, it does not have to be restudied; is that not the case?

Requirement R5.3 should be added stating something similar to "Multiple Transmission Owners of stations within proximity as determined in R2 shall share the results of their analyses related to the stations within proximity with all the other Transmission Owners of the stations within proximity."

Likes 0	
Dislikes 0	

Response

Thank you for your comments.

Requirement R5, Part 5.2 (now Part 5.3) only requires the Transmission Owner to identify its associated primary control center. No coordination with information security is required.

The word "previously" has been added back. Please see revised language in Requirement R5.

The drafting team made extensive modifications to better express the intent of the assessment as well as identification of associated primary control centers.

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford

Answer	No
Document Name	

Comment

There is no issue with performing a risk assessment every 36 months.

Reference responses to the previous questions on R3 & R4 regarding the appropriateness of the planning study being governed in the TPL space and not within CIP-014.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The second suggestion is out of scope of this project.	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE agrees with EEI's comments on clarification of Requirement 5.1 if a Transmission station or substation will need to be restudied every 36 calendar months after it's been already identified or keeping them on the list for a risk assessment is sufficient.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Please see the responses to the EEI's comments.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	No
Document Name	
Comment	
We suggest adding language about required actions where a TO designate another entity's Control Center in part 5.2. for instance, coordination between the entities and information security. Was "previously" meant to be struck in R5.1? The intent of this section was believed to be that if a station was previously found to be impactful, it does not have to be restudied; is that not the case? Requirement R5.3 should be added stating something similar to "Multiple Transmission Owners of stations within proximity as determined in R2 shall share the results of their analyses related to the stations within proximity with all the other Transmission Owners of the stations within proximity."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The word "previously" is added back. The drafting team made extensive modifications in Requirement R5 to better layout the intent of the assessment as well as identification of associated primary control centers.	

Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	No
Document Name	
Comment	
Please see Oncor's comments in response to Question 1, above.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see responses to Oncor's comment.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	No
Document Name	
Comment	
SERC appreciates the ongoing efforts to refine the CIP-014 Risk Assessment portion of the standard. SERC suggests the change from the phrase 'the primary control center' to 'each primary control center' to address real-world situations where different control centers may independently control different Elements within a Transmission station or substation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team would like to keep "the primary control center" for associated Elements as in the approved previous version. It is the Transmission Owner's responsibility to identify one primary control center associated with that particular Transmission station or Transmission substation.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
We request clarification of the phrase "rendered inoperable or damaged". There seems to be an incongruity between a facility that is simply damaged and one that is rendered inoperable. The phrase "or damaged" indicates a less severe impact than "rendered inoperable", for instance just a portion of the substation may be damaged. We request definitions for "inoperable" and "damaged", as recommended by the NERC 2023 CIP-014 evaluation report, to provide clear intent of the risk assessment. Please explain the technical basis for the change from 60 months (with no previous applicable substations identified) to 36 months for re-performance of the risk assessment. If no technical basis exists, we request the period be returned to the original 60 months. Reducing the period to 36 months will place additional burdens on Transmission Planners, which pulls resources from activities that are also important to grid reliability. Further, most	

significant EHV expansion projects which would alter the previous base case assumptions do not occur every 36 months and are more in line with 60-month construction periods.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. Regarding the use of "rendered inoperable or damaged", we note that this has existed in all versions of CIP-014; furthermore, we believe it is adequately explained through what is prescribed in the new Requirement R3.

The SAR required the DT to align multiple timelines in CIP-014-3. Requirement R1 is revised to ensure that each Transmission Owner establishes a list of applicable Transmission station(s) or Transmission substation(s) in accordance with Attachment 1. Aligning the 36 calendar months look ahead in Requirement R1 with the 36 calendar month risk assessment cycle ensures that system topology of the cases used to assess applicability is consistent with the system topology in the risk assessment models. The 36 calendar months cycle for updating the list of applicable Transmission station(s) or Transmission substation(s) per Attachment 1 aligns with the annual cycle for performing Planning Assessments per NERC Standard TPL-001. The 36 calendar months risk assessment study cycle aligns with the 36 calendar months planned-to-be-in-service date.

Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers

Answer	No
Document Name	

Comment

R5.1: Ameren would like more clarity around what is meant by additional simulations.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see revised language in the Standard. The drafting team made extensive modifications in Requirement R5 to clarify the intent of the assessment.

Jennifer Mcnally - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No
Document Name	

Comment

Duke Energy supports the overall modifications made in R5 and also supports EEI's ask for additional clarity in 5.1. We believe that the Drafting Team intended that stations and substations that have already been identified and protected will not require further assessment or demonstration of stability issues but can simply remain as identified and protected sites within an entity's program.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the response to the EEI's comments.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
R5. At least once every 36 calendar months, each Transmission Owner shall perform a risk assessment to identify Transmission station(s) and Transmission substation(s) that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection, using the methodology established in Requirement R3 including any Transmission station(s) and Transmission substation(s) for its assessment identified in R1 and R2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and suggestions. Please see revised language in Requirement R5. The drafting team made some modifications to better express the intend of the assessment.	
Ellese Murphy - Ellese Murphy On Behalf of: Katherine Street, Duke Energy , 5, 6, 1, 1; - Ellese Murphy	
Answer	No
Document Name	
Comment	
Duke Energy supports the overall modifications made in R5 and also supports EEI's ask for additional clarity in 5.1. We believe that the Drafting Team intended that stations and substations that have already been identified and protected will not require further assessment or demonstration of stability issues but can simply remain as identified and protected sites within an entity's program.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the response to the EEI's comments.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	
Salt River Project (SRP) agrees with EEI's comments on clarification of Requirement 5.1 if a Transmission station or substation will need to be restudied every 36 calendar months after it's been already identified or keeping them on the list for a risk assessment is sufficient.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. Please see responses to EEI's comments.	
Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA has identified that the SAR does not include content for when a problem needs resolution when there is Joint Ownership of a substation. The SAR's purpose only states "Clarify how to account for adjacent Transmission stations or Transmission substations of differing ownership as well as for those Transmission stations or Transmission substations within line-of-sight to each other." BPA recommends adding clarification for problem resolution to account for unforeseen circumstances.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Resolution process that may differ from region to region or company to company.	
Leshel Hutchings - AEP - 3	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
For the Drafting Teams consideration: Clarification is needed regarding stations and substations identified in previous risk assessments as causing instability, uncontrolled separation, or Cascading within an interconnection when rendered inoperable or damaged as a result of a physical attack if those substations will need to be studied is	

subsequent risk assessments. In other words, once a station or substation has been identified as 'critical' can the TO assume it will continue to be 'critical' without having to assess it again?	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. The answer is yes, once a station or substation has been identified as 'critical', the station will continue to be 'critical' without having to assess it again. Removing a station from the critical list, the TO has to re-assess it to approve it. Please see the language in Requirement R5, 5.2.	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	
Comment	
Please provide clarity on the differences between "inoperable" and "damaged" as a result of a physical attack. Consider adding examples to address various scenarios involving both the substation under study and adjacent substations within the ½ mile proximity.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. It is the position of the DT that citing specific examples would be inadvisable primarily due to grid security issues but also due to regional grid variances. As stated previously, we believe that "rendered inoperable or damaged" is adequately explained through what is prescribed in the new Requirement R3.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Tri-State supports MRO NSRF Comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. Please see responses to MRO NSRF's comments.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	

Answer	Yes
Document Name	

Comment
LG&E/KU supports the modifications in Requirement R5, but suggests two non-substantive clarifications. First, in the main body of Requirement R5 clarify, "… using the methodology established in Requirement R3 [*including any Transmission station(s) and Transmission substation(s) identified*] **and, where appropriate,** in accordance with **the responsibilities** document[*ation establish*]ed per Requirement R4." As currently written, this sentence implies additional Transmission station(s) and Transmission substation(s) are identified in Requirement R4. However, Requirement R4 only establishes responsibilities for stations with multiple owners. The suggested clarification sharpens the connection between Requirements R4 and R5. Second, in Requirement R5 Part 5.2 clarify, "… identified **as causing instability, uncontrolled separation, or Cascading within an Interconnection** in the Requirement R5 risk assessment." This Part previously said identified as "critical". Removing the undefined "critical" is a good change, but "identified" does not convey the same meaning on its own.

Likes 0	
Dislikes 0	

Response
Thank you for your support and comments. After the modification, the current revision says that "At least once every 36 calendar months, each Transmission Owner shall perform a risk assessment to identify applicable Transmission station(s) and Transmission substation(s) identified in Requirement R1, that if rendered inoperable or damaged could result in instability, uncontrolled separation, or Cascading within an Interconnection, using the methodology established in Requirement R3, including any Transmission station(s) and Transmission substation(s) identified in accordance with Requirement R4. If proximate Transmission station(s) and Transmission substation(s) were identified in Requirement R2, they should also be included in the risk assessment." The drafting team believes that this new language provides more clarity. Please see revised language in Requirement R5, Part 5.3. "as causing instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged" has been added as suggested.

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3

Answer	Yes
Document Name	

Comment
PNM and TNMP support EEI comments.

Likes 0	
Dislikes 0	

Response
Thank you for your support. Please see responses to the EEI's comments.

Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker

Answer	Yes
Document Name	
Comment	
Cleco agrees with EEI comments.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Please see responses to the EEI's comments.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI asks the drafting team to consider adding clarity to the technical rationale describing what is intended by Requirement R5, Part 5.1 that states "A Transmission station or Transmission substation identified in dynamic or steady-state simulations as causing instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged as a result of a physical attack does not require any additional simulations during the current risk assessment." It is not clear if the intention is for those stations and substations to be reassessed every 36 calendar months if they've already been identified, or if keeping them on the list for applying CIP-014 protections is sufficient after their initial assessment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. Please see revised language (R5.2) for clarification.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
NV Energy appreciates the drafting team reverting to the "identified" language of previous versions for continuity with the remainder of the requirements that remain unchanged. Can the drafting team provide more clarity on what is meant by "if rendered inoperable or damaged as a result of a physical attack"? Rendered inoperable appears to indicate a more severe impact where "or damaged" seems much less severe such as just a portion of a substation system. It is also not clear if rendered inoperable or damaged refers to the substation transmission system or the control and protection systems or both. This is a fundamental source of confusion as to how protection system functions are impacted and how/where faults should be applied for these studies that will be acceptable to auditors. For example, are faults applied simultaneously to different voltage levels, or only at the local substation under attack, or all included elements one at a time? This would seem to depend on the type of attack and what is rendered inoperable or damaged. The	

NERC 2023 CIP-014 evaluation report noted that a criterion should also include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear.

It is also unclear if the “physical attack” is on the primary transmission system such as occurring outside the fence remote to the substation or internal on the control house systems inside the substation, or if it is on all systems. An attack could mean there are explosives involved, gunshots remote from the substation, or invasive personnel onsite. Which of these are more likely? There should be more industry agreement on how an attack impacts a substation and the primary system and underlying control and protection systems. The open-ended nature of “physical attack” results in very different interpretations of severity and subsequent protection system fault modeling results. This could be especially true depending on substation locations and inherent risk differences throughout the country. Clarify if the decisions to the questions above are left up to each company and their own assessment methodology?

Add examples to the rationale to address the various scenarios involving a substation under study and any adjacent substations meeting the ½ mile proximity. For example: Are they faulted simultaneously or individually with or without the same damage or inoperability? Are these questions up to each individual assessment methodology?

Likes 0	
Dislikes 0	

Response

Thank you for your support and comments. Please see revised language to address your concerns (Requirement R3). Also, the DT provided the latitude for entities to define their own event while complying with the methodology requirements in R3.

TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF

Answer	Yes
Document Name	

Comment

Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana South (SIGE) supports the comments as submitted by Edison Electric Institute (EEI).

Likes 0	
Dislikes 0	

Response

Thank you for your support and comments. Please see responses to the EEI’s comments.

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

Answer	Yes
Document Name	

Comment

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #5.

Likes 0	
Dislikes 0	
Response	
Thank you for your support. Please see responses to the EEI's comments.	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
The R5 VRF Time Horizon still states it applies to 'Long-term Planning Horizon', whereas the NERC Glossary of Terms defines the 'Near-Term Planning Horizon' as the window covering year 1 through 5. This requirement references 'at least once every 36 calendar months', so it is recommended that the R5 VRF Time Horizon language is updated to reference the 'Near-Term Transmission Planning Horizon'.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. NERC Glossary of Terms is different from NERC Time Horizons. NERC Time Horizons define "Long-term Planning" as "a planning horizon of one year or longer". This document is located on NERC public site: Document Portrait.	
Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Please see responses to the EEI's comments.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	

Likes 0	
Dislikes 0	
Response	
Thank you for your support. Please see responses to the EEI's comments.	
Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Matthew Nicklin - Southern Illinois Power Cooperative - 1,3,5 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
James Keele - Entergy - 3	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Thank you for your support.

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Carver Powers - Utility Services, Inc. - 4

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Teresa Krabe - Lower Colorado River Authority - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
John Pearson - ISO New England, Inc. - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Stefanie Burke - Portland General Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Richard Vendetti - NextEra Energy - 5	
Answer	
Document Name	
Comment	
NextEra supports the comments provided by EEI below: EEI asks the drafting team to consider adding clarity to the technical rationale describing what is intended by Requirement R5, Part 5.1 that states “A Transmission station or Transmission substation identified in dynamic or steady-state simulations as causing instability, uncontrolled separation, or Cascading within an Interconnection when rendered inoperable or damaged as a result of a physical attack does not require any additional simulations during the current risk assessment.” It is not clear if the intention is for those stations and substations to be reassessed every 36 calendar months if they’ve already been identified, or if keeping them on the list for applying CIP-014 protections is sufficient after their initial assessment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support and comments. Please see responses to the EEI’s comments.	

6. Do you agree with the Implementation Plan for CIP-014-4?

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

The CIP-014-4 standard introduces a significant change by requiring the inclusion of stations within a 1/2-mile line of sight or easily accessible from a common roadway. However, the standard lacks clear guidelines for selecting stations. This could lead to inconsistencies and challenges in implementation, as different Transmission Owners and Transmission Operators may interpret and apply the criteria differently.

To improve clarity and ensure consistent implementation, the standard should provide more detailed guidance on the selection of stations, including specific criteria for evaluating lines of sight and ease of access from common roadways. This would help Transmission Owners and Transmission Operators to better understand the requirements and apply them consistently, ensuring the reliability and security of the electrical grid.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the revised Standard for your concern. In addition, the initial performance of periodic Requirements is clarified in the Implementation Plan.

Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1

Answer	No
Document Name	

Comment

NIPSCO agrees with Southern CO:

It potentially could be excessively burdensome on a Transmission Owner (TO) to be required to perform a new risk assessment study within 24 months of the effective implementation date of the revised CIP-014-4 standard. Additionally, limited resources may be available to complete a verification within 90 days of the effective date per Requirement R6.

For example, given the current CIP-014-3 R1.1 30 calendar month subsequent risk assessment requirement schedule for a TO which has substations identified under R1, the TO may currently be required to complete a subsequent R1 study as of September 30, 2025.

If the revised standard has an effective implementation date of October 1, 2025, the TO would be required to complete a new R1 study within 24 months of October 1, 2025. A more effective and efficient

methodology is a phased approach based on the TO's completion date of the TO's most recent R1.1 subsequent risk assessment study.

Proposed Language: Each TO shall conduct its first assessment under CIP-014-4 within 36 calendar months after the effective date or within 36 calendar months after their last assessment under CIP-014-3, whichever occurs later.

Likes 0	

Dislikes 0	
Response	
Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
For entities with facilities spread over many states that were constructed at significantly different times, the additional work included in this version will make it more complicated to complete by the effective date. Additional constraints with completing the required work will occur depending on the timing of their compliance with the existing version. An additional 6 months, or 30 months, would make this more feasible.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan.	
TRACEY JOHNSON - Southern Indiana Gas and Electric Co. - 3,5,6 - RF	
Answer	No
Document Name	
Comment	
SIGE proposes to increase the implementation plan to 36 calendar months to align with the standard and give the industry more time to implement the changes in CIP-014-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan.	
Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	No
Document Name	
Comment	
N/A	
Likes 0	

Dislikes 0	
Response	
Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE proposes to extend the implementation plan to 36 calendar months to align with the standard and give the industry more time to implement the changes in CIP-014-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
There should be some period of time after the standard becomes effective before the risk assessment should be completed. The recommendation is within 24 months following the effective date of this standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan.	
Jessica Cordero - Unisource - Tucson Electric Power Co. - 1	
Answer	No
Document Name	
Comment	
Recommending making CIP-014-4 effective 12 months after applicable government authority approval. The first assessment under CIP-014-4 shall be completed at the earlier of the following:	

- Within 30 calendar months of its previous risk assessment under CIP-014-3 if it identified one or more transmission stations or transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or cascading within its interconnection in its last CIP-014-3 risk assessment;
- Within 60 calendar months of its previous risk assessment under CIP-014-3 if it did not identify any transmission stations or transmission substations that if rendered inoperable or damaged could result in instability, uncontrolled separation, or cascading within its interconnection in its last CIP-014-3 risk assessment;
- Within 24 months of the effective date of CIP-014-4.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan. Based on the industry comments a majority of entities expressed that they need more than 12 months to be ready to comply with CIP-014-4 after applicable government authority approval.

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3

Answer	No
Document Name	

Comment

PNM and TNMP suggest phased implementation. For example >=24 months to comply with R1-R4 on or before effective date and “initial R5 risk assessment” some period, e.g. 12 calendar months, after effective date.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan.

Matt Carden - Southern Company - Southern Company Services, Inc. - 1

Answer	No
Document Name	

Comment

It potentially could be excessively burdensome on a Transmission Owner (TO) to be required to perform a new risk assessment study within 24 months of the effective implementation date of the revised CIP-014-4 standard. Additionally, limited resources may be available to complete a verification within 90 days of the effective date per Requirement R6.

For example, given the current CIP-014-3 R1.1 30 calendar month subsequent risk assessment requirement schedule for a TO which has substations identified under R1, the TO may currently be required to complete a subsequent R1 study as of September 30, 2025.

If the revised standard has an effective implementation date of October 1, 2025, the TO would be required to complete a new R1 study within 24 months of October 1, 2025. A more effective and efficient methodology is a phased approach based on the TO’s completion date of the TO’s most recent R1.1 subsequent risk assessment study.

Proposed Language: Each TO shall conduct its first assessment under CIP-014-4 within 36 calendar months after the effective date or within 36 calendar months after their last assessment under CIP-014-3, whichever occurs later.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan. The drafting team believes that 24 calendar months is adequate for the industry to prepare for the new revision of the Standard. Since the current version of CIP-014-3 is on a 30-month cycle, there are a few extra months added for process before Board of Trustee and FERC for adoption/approval once the Standard gets approved by the industry.

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

Answer	No
Document Name	

Comment

FirstEnergy sees the current version requiring a 2-year cycle. With the implementation of CIP-014-4, has Drafting Team considered a 5-year gap that could result in the implementation of the newest version?

FirstEnergy also supports EEI Comments which state:

EEI is concerned that the implementation plan requires the initial risk assessment required by CIP-014-4 to be completed on or before the effective date of the Standard and does not provide a phased in approach. The modifications required by the proposed CIP-014-4 include new processes to be established prior to initiating new risk assessments. The proposed 24-month timeline is not reasonable for completing the initial risk assessment. EEI suggests allowing the initiation of CIP-014-4 risk assessments to occur on or before the effective date of the standard to allow additional time to modify programs.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan. Based on the current Implementation Plan drafted, the greatest time gap would be 30 calendar months.

Leshel Hutchings - AEP - 3

Answer	No
Document Name	

Comment

The proposed implementation plan is 24 months. This means some Transmission Owners may have insufficient time, less than 36 months, to complete their next assessment based on the new standard. Example: a TO with an existing compliance deadline at the end of this year may fall under the shortened timeline. For large TOs, the existing applicability scoring, case prep, steady state and stability analysis, and third-party review can take as long as 1 year to perform per region. AEP has three regions (PJM, SPP, and ERCOT), which each take this amount of time. With the proposed proximity/applicability changes, scenario changes, and this implementation period would be insufficient time to adopt and reperform the assessment. In addition, given the new proximity criteria some small TOs may not have had any applicable stations previously and will have to create a new methodology and perform the assessment from scratch within that short 24-month period.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan.

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis

Answer	No
Document Name	

Comment

MPC disagrees with the requirement to perform an analysis under CIP-014-4 prior to the effective date of the standard. This will very likely require utilities to perform a largely duplicative analysis in less than 30 months from their previous analysis. Such a duplicative analysis increases the study burden on utilities for no foreseeable benefit to BES reliability.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan.

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA appreciates the addition of the clarifying language about the first R5 due date. However, BPA identifies a potential overlap or gap when considering the current review cycle for the standard against a 24-month implementation plan. It is possible that an entity would have to adopt the new language extremely early to align with its next Version 3 cycle or perform an extra round of CIP-014 activities during the period in between Version 3 activities. BPA recommends using terminology such as that found in other standards such as FAC-014-3 R6:

"Requirement R6 shall be implemented by the Planning Coordinator or Transmission Planner following the effective date of FAC-014-3 when it begins its next cycle for conducting the studies to support its Planning Assessment."

BPA believes the inclusion of this language would help to reduce overall costs for the implementation of the changes.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The initial performance of periodic Requirements is clarified in the Implementation Plan.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB	
Answer	No
Document Name	
Comment	
TVA proposes to increase the implementation plan to 36 calendar months to align with the standard and give the industry more time to implement the changes in CIP-014-4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The initial risk assessment required by Reliability Standard CIP-014-4 Requirement R5, must be completed on or before the effective date of the standard. Subsequent risk assessments shall be performed no later than 36 calendar months following the effective date of Reliability Standard CIP-014-4 The implementation plan would then allow 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.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	Yes
Document Name	
Comment	
Salt River Project (SRP) supports the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Selene Willis - Edison International - Southern California Edison Company - 5	
Answer	Yes
Document Name	
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	

Thank you for your support. Please see responses to EEI's comments.

Robert Blackney - Edison International - Southern California Edison Company - 1	
Answer	Yes
Document Name	
Comment	
See comments submitted by EEI.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support. Please see responses to EEI's comments.	
Ellese Murphy - Ellese Murphy On Behalf of: Katherine Street, Duke Energy , 5, 6, 1, 1; - Ellese Murphy	
Answer	Yes
Document Name	
Comment	
Duke Energy supports the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennifer Mcnally - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	Yes
Document Name	
Comment	
Duke Energy supports the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dwanique Spiller - Berkshire Hathaway - NV Energy - 5	

Answer	Yes
Document Name	
Comment	
NV Energy agrees that 24 months is reasonable for implementation.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Stefanie Burke - Portland General Electric Co. - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Teresa Krabe - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Vendetti - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Alan Kloster - Alan Kloster On Behalf of: Jeremy Harris, Evergy, 3, 5, 1, 6; Kevin Frick, Evergy, 3, 5, 1, 6; Marcus Moor, Evergy, 3, 5, 1, 6; Tiffany Lake, Evergy, 3, 5, 1, 6; - Alan Kloster	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Sean Steffensen - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thank you for your support.	
Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ben Hammer - Western Area Power Administration - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Joshua London - Eversource Energy - 1, Group Name Eversource	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Matthew Nicklin - Southern Illinois Power Cooperative - 1,3,5 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thank you for your support.	
Tamarra Hardie - Tamarra Hardie On Behalf of: Diane E Landry, Public Utility District No. 1 of Chelan County, 3, 5, 1, 6; - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Mark Flanary - Midwest Reliability Organization - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jeffrey Streifling - NB Power Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Kevin Conway - Western Power Pool - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE recommends the implementation plan specify the list shall be established by the effective date of the standard to avoid delaying compliance obligations an additional 36 months. Absent a specified initial performance date in the implementation plan, the Transmission Owner would have until 36 months after the effective to establish its first list of Transmission station(s) and Transmission substation(s).	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments and recommendations. Please see revised Implementation Plan.	

7. Do you agree that CIP-014-4 is cost effective to address the reliability issue of physical security? If no, why not?

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

BPA does not believe the standard, as is, is cost effective in addressing the reliability of physical security. The spectrum of sites is too broad. BPA believes there is high potential for sites to be identified on CIP-014-4 list that would have little to no effect on the BES if they were disconnected from the grid. The standard, as is, allows sites with RAS capability to be listed as CIP-014, which mitigates an enormous amount of risk, some might argue all. The number of sites that could potentially be categorized as CIP-14 takes resources away from other sites along critical pathways, and sites that directly link to critical infrastructure. Additionally, day-to-day operations of upstream and downstream sites affect whether singular or multiple pieces of equipment in a site are critical. BPA finds the inclusions of R2.1 and R2.2 are so broad as to compound the issues of cost without a large gain in security or reliability. BPA believes the increase in CIP-014 applicability may require more resources than some smaller Transmission Owners have at their disposal. This increase will not only strain the resources of those smaller Transmission Owners but those of larger size within a BA that may be called upon to assist.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis

Answer	No
Document Name	

Comment

Requiring the CIP-014 risk assessment every 36 months for utilities who have not previously identified any stations or substations as critical is not cost effective; see MPC's comments in response to Question 5.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. If you do not have any stations meeting Attachment 1 criteria, you do not need an assessment. If your system has not changed, the chances are you will remain the same. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.

Leshel Hutchings - AEP - 3

Answer	No

Document Name	
Comment	
While this SAR focused on the R1 risk assessment, the most effective protection against all possible threat vectors is to plan redundancy into the Transmission system to remove single points of failure. Protecting individual stations against specific threats will always be less effective than Transmission build out. The standard should be revised to consider Transmission Planning mitigations rather than defaulting to adding physical security.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team appreciates your feedback.	
Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna	
Answer	No
Document Name	
Comment	
Performing the risk assessment every 36 months rather than every 60 months for those entities with no applicable stations/substations in the previous risk assessment does increase cost for TOs internally and increases the cost of using an unaffiliated 3rd party to verify the risk assessment. Also, it is expected with the newly added 'proximity within 1/2 mile', stations/substations in R2 will incur additional cost burden and not be cost effective, especially if the station/substation in 'proximity within 1/2 mile' is also found to be applicable and requires physical security enhancements to address any potential threats and/or vulnerabilities.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS. The DT also reduced the ½ mile to 1500 feet.	
Matt Carden - Southern Company - Southern Company Services, Inc. - 1	
Answer	No
Document Name	
Comment	
Southern Company recognizes the financial impacts of performing the risk assessment every 36 months rather than 60 months for Transmission Owners that have not identified any Transmission stations or Transmission substations. This is magnified by the requirement to have an unaffiliated third party verify the risk assessment at a higher frequency.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS. In the previous version of CIP-014, the 30-month time frame and the 24-month planned-to-be-in-service date could, if not carefully applied, lead to gaps between models and study horizons. Aligning the 36 calendar months look ahead in Requirement R1 with the 36 calendar month risk assessment cycle ensures that system topology of the cases used to assess applicability is consistent with the system topology in the risk assessment models. It is necessary to perform the risk assessment every 36 months and closing the gap for reliability is the priority.	
Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3	
Answer	No
Document Name	
Comment	
Increasing the frequency of risk assessments, including the R6 requirement for third-party validation causes increase demand on resources. The cost seems disproportionate to the potential benefit.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.	
Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	No
Document Name	
Comment	
The issues of requiring Transmission Owners perform a Transmission Planning/Planning Coordinator function is problematic and makes assessment of cost-effectiveness unclear. Additionally, this dynamic will continue to lead to lack of clarity and consistency in the auditing of this standard which could result in cost and workload to address/respond to the requirements and audit reviews. Additionally, the requirement to add stations that are within a ½ mile radius of applicable stations will add more cost without any justification for the requirement. Furthermore, requiring a third-party verification of a planning assessment appears to be an unnecessary expense. Is there supporting evidence from the 2015 – 2024 time-period to show the benefits of this verification?	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see revised Standard. The drafting team appreciates your feedback on cost effective. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS. The drafting team has reduced ½ mile to 1500 feet or 457 meters (the shortest distance, measured substation fence line to substation fence line) of an applicable Transmission station or Transmission substation identified in Requirement R1. This should reduce some cost.	

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CEHE believes increasing the study requirements and processes will cause an additional burden on TPs and the additional engineering hours will not be cost effective with current resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team is aware that increasing the Requirements seems to increase the work, in order to meet the SAR work scope.The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.	
Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	No
Document Name	
Comment	
The comments above demonstrate that additional clarity is needed on certain portions of this revised CIP-014-4. Without that additional clarity, Oncor cannot state that the proposed changes to CIP-014-3 are cost effective. As noted above, some of these proposed revisions create additional burdens on TOs that could increase costs to TOs. For example, the additional burdens on TOs created in R2 and R4 will require new procedures and processes to be developed, documented, approved, and implemented – including the development and implementation of additional training concerning the new requirements.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	No
Document Name	
Comment	
Eliminate the third-party review included in Requirement R10. This is a considerable expense and has not been proven to add value to the Standard, having been disregarded by enforcement entities during numerous compliance monitoring activities. Please retire Requirement R10.	

Likes 0	
Dislikes 0	

Response

Thank you for the comment. Third party verification was previously approved. The drafting team believes that having an unaffiliated third party review the evaluation performed under Requirement R8 and the security plan(s) developed under Requirement R9 is critical to reliability. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.

Teresa Krabe - Lower Colorado River Authority - 5

Answer	No
Document Name	

Comment

The cost-effectiveness of CIP-014-4 in addressing physical security and reliability concerns is not entirely clear. The changes introduced, particularly regarding proximity criteria, may lead to a broader range of substations being classified for criticality assessment. This expansion could result in increased costs for compliance and implementation.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.

James Baldwin - James Baldwin On Behalf of: Matt Lewis, Lower Colorado River Authority, 5, 1; - James Baldwin

Answer	No
Document Name	

Comment

The cost-effectiveness of CIP-014-4 in addressing physical security and reliability concerns is not entirely clear. The changes introduced, particularly regarding proximity criteria, may lead to a broader range of substations being classified for criticality assessment. This expansion could result in increased costs for compliance and implementation.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.

Jennifer Mcnally - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF

Answer	No

Document Name	
Comment	
Duke Energy does not agree that CIP-014-4 is cost effective as proposed due to the ambiguity that still exists in the requirement language.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see revised Standard. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	No
Document Name	
Comment	
There are two requirements that increase the cost to complete this study that do not improve reliability significantly. The first is R4. Collecting existing documentation on compliance responsibilities will only improve reliability if neither entity is performing a CIP-014 on specific sites. In NERC's, report this was not identified as a reliability gap. The second is for R2 where entities need to one share their existing and planned future applicable sites with other entities in order to receive data on whether or not they have or plan to build a transmission site nearby. Based on the footprints and configurations of a Transmission Owners facilities, this could involve disclosing to a number of entities information that is deemed sensitive if not CEII.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see revised Standard. Requirement R2 provides applicable entities clarification on which station(s) and substation(s) are applicable. Because the CIP-014-4 Risk Assessment Refinement SAR calls for clarification regarding Transmission substations and Transmission stations of differing ownership, this section was clarified in Requirement R4. Requirement R4 is to close the reliability gaps on different ownership of the stations. This issue was missing from the standard language. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.	
Ellese Murphy - Ellese Murphy On Behalf of: Katherine Street, Duke Energy , 5, 6, 1, 1; - Ellese Murphy	
Answer	No
Document Name	
Comment	
Duke Energy does not agree that CIP-014-4 is cost effective as proposed due to the ambiguity that still exists in the requirement language.	
Likes 0	
Dislikes 0	

Response	
Thank you for the comment. Please see revised Standard. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.	
Alison Nickells - NiSource - Northern Indiana Public Service Co. - 1	
Answer	No
Document Name	
Comment	
Increasing the frequency of risk assessments, including the R6 requirement for third-party validation causes increase demand on resources. The cost seems disproportionate to the potential benefit.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see revised Standard. The third party verification was approved by the industry from the previous version. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	No
Document Name	
Comment	
It is not clear to us if CIP-014-4 is cost effective to address reliability issue of physical security. Changes introduced in CIP-014-4 with respect to proximity criteria (R1 and R2) may result in additional stations becoming applicable for criticality assessment, thereby potentially increasing costs.	
Likes 0	
Dislikes 0	
Response	
Thank you for the comment. Please see the revised Standard. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.	
Israel Perez - Israel Perez On Behalf of: Laura Somak, Salt River Project, 3, 6, 5, 1; Mathew Weber, Salt River Project, 3, 6, 5, 1; Thomas Johnson, Salt River Project, 3, 6, 5, 1; Timothy Singh, Salt River Project, 3, 6, 5, 1; - Israel Perez	
Answer	No
Document Name	
Comment	

Salt River Project (SRP) agrees with PNM that increasing the frequency of risk assessments, including the R6 requirement for third-party validation causes increase demand on resources. In addition, this would add additional burden on the Transmission Planners and additional resources would need to be allocated to meet the Standard.

Likes 0	
Dislikes 0	

Response

Thank you for the comment. Please see the revised Standard. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle

Answer	No
Document Name	

Comment

We cannot comment on cost effectiveness.

Likes 0	
Dislikes 0	

Response

Thank you.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you.

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

Answer	Yes
Document Name	

Comment

FirstEnergy sees no issues in the cost effectiveness of the proposed CIP-014-4 standard.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

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

Answer	Yes
Document Name	

Comment

In the confines of, does the updated language cost effectively address the reliability issue of physical security from version to version of CIP-014, we would have to agree.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Jeffrey Streifling - NB Power Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	

Dislikes 0	
Response	
Thank you for your support.	
Tamarra Hardie - Tamarra Hardie On Behalf of: Diane E Landry, Public Utility District No. 1 of Chelan County, 3, 5, 1, 6; - Public Utility District No. 1 of Chelan County - 6, Group Name CHPD	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Matthew Nicklin - Southern Illinois Power Cooperative - 1,3,5 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
James Keele - Entergy - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Ben Hammer - Western Area Power Administration - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Gary Trezza - Long Island Power Authority - 1 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Carver Powers - Utility Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	

Response

Thank you for your support.

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

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Tim Kelley - Tim Kelley On Behalf of: Charles Norton, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Foung Mua, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Ryder Couch, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; Wei Shao, Sacramento Municipal Utility District, 3, 6, 4, 1, 5; - Tim Kelley, Group Name SMUD and BANC

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Robert Jones - Seattle City Light - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Jennie Wike - Jennie Wike On Behalf of: John Merrell, Tacoma Public Utilities (Tacoma, WA), 1, 4, 5, 6, 3; - Jennie Wike, Group Name Tacoma Power	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Dave Krueger - SERC Reliability Corporation - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Amy Wilke - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	

Kevin Conway - Western Power Pool - 4	
Answer	
Document Name	
Comment	
The SAR states: "The cost impacts for the proposed changes to CIP-014-3 are expected to be minimal. The changes add clarity to the current Standard to bring consistency and clarify expectations for effectively evaluating for instability, uncontrolled separation, and Cascading following a physical attack. The upper limit of cost added to entities is bounded due to no alteration of applicable substations potentially receiving security control upgrades. Rather, the cost incurred will be on the additions of study rigor, which again are anticipated to be relatively minimal." The Drafting team has not provided additional data, and the dynamic and steady-state requirements are outside of the TO's area of responsibility. This requires a TO to access this expertise through contracting or other methods. The Drafting Team has failed to identify how this Standard may further capture additional Facilities, and require entities to take further security mitigations. The Implementation Plan will require entities to reevaluate all of the risk assessment processes sooner that the current 36-month review period, since they will have to be compliant with all Facilities with 24 months of the proposed standard. This proposed standard fails to conduct a cost impact study, and we believe there are significant hidden costs in implementing this proposed standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see the revised standard. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.	

Donna Wood - Tri-State G and T Association, Inc. - 1	
Answer	
Document Name	
Comment	

NA

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	

Comment

The second draft of CIP-014-4 sufficiently addresses many of the issues described in the SAR and provides an appropriate level of detail in the risk assessment requirements. Broadly, the second draft of CIP-014-4 is an improvement on CIP-014-3 and will improve consistency in risk assessment methodology throughout the industry. The cost effectiveness of CIP-014-4 for addressing physical security is difficult to determine, but the improvements over CIP-014-3 are appreciated.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see the revised Standard. The drafting team balanced concerns regarding the burden on applicable Transmission Owners and the benefits to reliability from identifying and physically protecting those Transmission stations, Transmission substations, and their associated primary control centers that are critical to the reliable and secure operation of the BPS.

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI does not comment on cost.

Likes 0	
Dislikes 0	

Response

Thank you.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	
Document Name	

Comment	
NV Energy will not comment to the cost effectiveness of CIP-014-4.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Nick Leathers - Nick Leathers On Behalf of: David Jendras Sr, Ameren - Ameren Services, 3, 6, 1; - Nick Leathers	
Answer	
Document Name	
Comment	
Ameren has no comment on the cost effectiveness of the project.	
Likes 0	
Dislikes 0	
Response	
Thank you.	
Rachel Schuldt - Black Hills Corporation - 6, Group Name Black Hills Corporation - All Segments	
Answer	
Document Name	
Comment	
Black Hills Corporation will not comment on cost effectiveness.	
Likes 0	
Dislikes 0	
Response	
Thank you.	

8. Provide any additional comments for the standard drafting team to consider, if desired.

Amy Wilke - American Transmission Company, LLC - 1	
Answer	
Document Name	
Comment	

Overall, ATC can stand behind most of the changes but would like to see updates on Requirement R2 before moving forward.

Additionally, please clarify in this standard if TOs and TOPs still need to do a study or assessment on previously qualified facilities if our company's corporate security team has voluntarily determined they were going to implement the highest level of physical security they have for a new or existing site. Does the SDT intend for TOs and TOPs to have to study those sites if they were already going to be classified at that high level of security. If not, this would be a really good exception to note that would save many companies a lot of time and effort.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The language in Requirement R2 to specify the distance between applicable stations has been revised. Language that the TO may forgo additional assessments has been added as Part 5.2 of Requirement R5. The language for Requirement R3 in the Technical Rationale document was updated.

Bob Cardle - Bob Cardle On Behalf of: Marco Rios, Pacific Gas and Electric Company, 3, 1, 5; Sandra Ellis, Pacific Gas and Electric Company, 3, 1, 5; Tyler Brun, Pacific Gas and Electric Company, 3, 1, 5; - Bob Cardle	
Answer	
Document Name	
Comment	

The CIP-014-4 standard introduces a significant change by requiring the inclusion of stations within a 1/2-mile line of sight or easily accessible from a common roadway. However, the standard lacks clear guidelines for selecting stations. This could lead to inconsistencies and challenges in implementation, as different Transmission Owners and Transmission Operators may interpret and apply the criteria differently.

To improve clarity and ensure consistent implementation, the standard should provide more detailed guidance on the selection of stations, including specific criteria for evaluating lines of sight and ease of access from common roadways. This would help Transmission Owners and Transmission Operators to better understand the requirements and apply them consistently, ensuring the reliability and security of the electrical grid.

Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The language in Requirement R2 to specify the distance between applicable stations has been revised.

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

Document Name	
Comment	
Salt River Project (SRP) agrees with the EEI comment to review the Attachment 1, Criterion 3 reference to IROLs.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Modifications to the Applicability, including revision of language related to Interconnection Reliability Operating Limits (IROLs), are beyond the scope of Project 2023-06. Please also see response to EEI's comments.	
Kelley Sargent - Puget Sound Energy, Inc. - 3	
Answer	
Document Name	
Comment	
It is not clear the type of events CIP-014-4 intends to address that can simultaneously impact 2 or more stations. The standard depends on physical security measures to mitigate such events, however mitigation to the extent may not be feasible nor cost effective.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in Requirement R2 to specify the distance between applicable stations has been revised.	
Romel Aquino - Edison International - Southern California Edison Company - 3	
Answer	
Document Name	2023-06 Unofficial_Comment_Form_Draft 2 - Final EEI Comments (1).docx
Comment	
See EEI Comments	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Please see response to EEI's comments.	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators	
Answer	
Document Name	

Comment	
We would like to thank the SDT for it's hard work and allowing us to provide feedback.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support.	
Ellese Murphy - Ellese Murphy On Behalf of: Katherine Street, Duke Energy , 5, 6, 1, 1; - Ellese Murphy	
Answer	
Document Name	
Comment	
Duke Energy thanks the Drafting team for their work on the revisions and for incorporating stakeholder feedback from Draft 1 into Draft 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support.	
Gail Elliott - Gail Elliott On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1; - Gail Elliott	
Answer	
Document Name	
Comment	
ITC is concerned that the proposed CIP-014-4, Attachment 1, Criterion 3 does not align with revisions to FAC-014-3 that became effective on April 1, 2024, which places the responsibility for establishing Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area with the Reliability Coordinator in accordance with its system operating Limit methodology (SOL methodology). We suggest the revision below: 3.Facilities at a single station or substation location that are identified by its Reliability Coordinator as critical to the derivation of Interconnection Reliability Operating Limits (IROLs) and their associated contingencies.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT recognized the discrepancy between this project and FAC-014-3. There is a new project (SAR has been approved) under CIP-002 to fix this particular issue (CIP-014 is part of that project).	
Jennifer Mcnally - Duke Energy - 1,3,5,6 - Texas RE,SERC,RF	
Answer	

Document Name	
Comment	
Duke Energy thanks the Drafting team for their work on the revisions and for incorporating stakeholder feedback from Draft 1 into Draft 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment and support.	
Lidija Efremova - Lidija Efremova On Behalf of: Emma Halilovic, Hydro One Networks, Inc., 1; - Lidija Efremova	
Answer	
Document Name	
Comment	
Can the standard also provide a process diagram showing activities (at least for the Risk Assessment portion) alongside a time scale which would help to show the overlap of frequency of report (start to start) overlapping with how far the study should look out for facilities to be in-service. This has been a source of confusion in the industry and although was not required in the SAR, will help to clarify many misunderstandings.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. A process diagram has been developed and added to the Technical Rationale document.	
Jamison Cawley - Nebraska Public Power District - 1	
Answer	
Document Name	
Comment	
Please provide clarification if “Line” includes long bus transformer connections between substations. Consider adding clarification or examples to the rationale as well. The example figure on Page 6 in the technical rationale highlights the 230kV line but does not indicate the status of the generation ties as included or excluded, nor does it show any tie transmission examples. Consider adding more detail and discussion for this figure.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The DT believes that criteria in the Attachment 1 is sufficiently clear, and specifically for part 2 of Attachment 1 that all lines should be counted unless terminating at a collecting bus.	
Dave Krueger - SERC Reliability Corporation - 10	

Answer	
Document Name	
Comment	

SERC appreciates the ongoing efforts to refine the CIP-014 Risk Assessment portion of the standard. With the revisions to R1-R3, it is unclear how SAR Scope item #2 “Clarify the case(s) used for the risk assessment to be tailored to the Requirement R1 in-service window and correct any discrepancies between the study period, frequency of study, and the base case(s) a Transmission Owner uses.” Is being addressed, in order to insure high accuracy and fidelity to actual planned system conditions within the 36 month time period are addressed.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. In accordance with Requirement R1, each Transmission Owner shall at least once every 36 calendar months document existing or planned to be in service within 36 calendar months Transmission stations and Transmission substations. In accordance with Requirement R5, each Transmission Owner shall perform a risk assessment at least once every 36 calendar months. Requirement R3 Part 3.2 has been revised to provide additional clarity related to the base cases.

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

Answer	
Document Name	
Comment	

Evergy supports and incorporates by reference the comments of the Edison Electric Institute for question #8.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to EEI’s comments.

Richard Vendetti - NextEra Energy - 5

Answer	
Document Name	
Comment	

NextEra supports the comments provided by EEI below:

EEI is concerned that the proposed CIP-014-4, Attachment 1, Criterion 3 does not align with revisions to FAC-014-3 that became effective on April 1, 2024, which places the responsibility for establishing Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area with the Reliability Coordinator in accordance with its system operating Limit methodology (SOL methodology). We suggest the revision below:

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

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to EEI's comments.

Stefanie Burke - Portland General Electric Co. - 6

Answer	
Document Name	

Comment

PGE supports the comments of EEI.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to EEI's comments.

Robert Jones - Seattle City Light - 4

Answer	
Document Name	

Comment

To reiterate my comment from R3... we have experienced disagreement with regulators about what type of physical attack we are supposed to be simulating. The regulators we spoke with expected a severe "smoking crater" scenario, but our physical security personnel suggested looking at what the most likely scenarios would be (i.e. things seen in previous incidents). The standard provides no guidance here and leaves the choice of scenarios up to us. The type of attack to expect is not something that seems like it would vary by utility, so it makes sense that the standard would specify this rather than leaving it up to individual entities to determine. Some guidance in the standard would help clear up the ambiguity so that we can choose appropriate contingencies to run and avoid friction with regulators.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to Question #3.

Dwanique Spiller - Berkshire Hathaway - NV Energy - 5

Answer	

Document Name	
Comment	

NV Energy thanks the drafting team for their responsiveness to industry comments on the initial draft.

Attachment 1 clarify if “Line” also includes long bus transformer connections between substations? Consider adding clarification or examples to the rationale as well. The example figure on page 6 in the technical rationale highlights the 230kV transmission lines but does not indicate the status of the generation ties as included or excluded or show any transmission tie transformer examples. Consider adding more details and discussion for this figure.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Line in Attachment 1 – Applicability Criteria refers to BES Transmission Lines.

Kristine Martz - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

EEI is concerned that the proposed CIP-014-4, Attachment 1, Criterion 3 does not align with revisions to FAC-014-3 that became effective on April 1, 2024, which places the responsibility for establishing Interconnection Reliability Operating Limits (IROLs) for its Reliability Coordinator Area with the Reliability Coordinator in accordance with its system operating Limit methodology (SOL methodology). We suggest the revision below:

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

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The DT recognized the discrepancy between this project and FAC-014-3. There is a new project (SAR has been approved) under CIP-002 to fix this particular issue (CIP-014 is part of that project).

Daniel Gacek - Exelon - 1

Answer	
Document Name	

Comment

Exelon agrees with the EEI comment to review the Attachment 1, Criterion 3 reference to IROLs. Project 2015-09 made changes to the determination of IROLs that may impact the use if IROL in CIP-014.

Exelon suggests the drafting team initiate edits to the CMEP Practice Guide for CIP-014 to align the practice guide with the expansion of the R1 into R1 to R5.

Submitted on behalf of Exelon - Segments 1 & 3	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Modifications to the Applicability, including revision of language related to Interconnection Reliability Operating Limits (IROLs), are beyond the scope of Project 2023-06. Please also see response to EEI's comments. CMEP Practice Guides are developed solely by the ERO Enterprise. This information has passed onto NERC Compliance Group.	
Andrew Smith - APS - Arizona Public Service Co. - 5	
Answer	
Document Name	
Comment	
AZPS appreciates the clarifications included by the DT in this draft, however continues to seek additional clarifications regarding entity responsibilities or exclusion of responsibilities for non-owned/operated stations/substations within proximity of identified locations. For example, the relationship and requirements between Transmission Owners and Transmission Operators when adjacent facilities are involved is not clear. The Transmission Owner and Transmission Operator can be different entities and R8 states the notification is made to the adjacent Transmission Operator. The Transmission Owner performing the assessment and identifying the facilities in R5 will be subject to doing the Physical assessments and protection, however it is not clear how the Transmission Owner of the adjacent facility is notified and what, if any, requirements they have.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The language in Requirement R2 to specify the distance between applicable stations has been revised. Changes to existing Requirements R4 through R6, in CIP-014-3, is beyond the scope of Project 2023-06.	
Lucinda Bradshaw - Lucinda Bradshaw On Behalf of: Byron Booker, Oncor Electric Delivery, 1; - Lucinda Bradshaw	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Thank you for your support.	
Chantal Mazza - Chantal Mazza On Behalf of: Junji Yamaguchi, Hydro-Quebec (HQ), 1, 5; Nicolas Turcotte, Hydro-Quebec (HQ), 1, 5; - Chantal Mazza	
Answer	

Document Name	
Comment	

We suggest adding triggers or process diagram similar to PRC-004 for required actions if ownership changes.

R6.3: Request R6.3 allow for 90 days instead of 60 so proper work can be completed. With a more detailed analysis being required, there is a higher chance of disagreement with our third party reviewer, requiring more time needed for response.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see a flowchart at the end of the Technical Rationale document. Changes to, in CIP-014-3, existing Requirements R4 through R6 is beyond the scope of Project 2023-06.

Diana Aguas - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

There is a typo in R8 Section 8.3. “Electricity Sector Information Sharing and Analysis Center (ES-ISAC)” should say “Electricity Information Sharing and Analysis Center (E-ISAC)”.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. While changes to CIP-014-3, existing Requirements R4 through R6 is beyond the scope of Project 2023-06, the typo of E-ISAC in Requirement R8 Part 8.3 has been corrected.

Clay Walker - Clay Walker On Behalf of: Robert Hirchak, Cleco Corporation, 6, 5, 1, 3; - Clay Walker

Answer	
Document Name	

Comment

Cleco agrees with EEI comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to EEI’s comments.

Stephen Stafford - Stephen Stafford On Behalf of: Greg Davis, Georgia Transmission Corporation, 1; - Stephen Stafford	
Answer	
Document Name	

Comment

The primary issue with this standard as it is written, and as this draft continues is the application of requirements/expectations appropriate for the Transmission Planner/Planning Coordinator function to the Transmission Owner instead. This reduces clarity on the types of studies to be performed to assess the extreme events identified in this standard.

Regarding R6:

With an attempt at clarifying study criteria, though they should be applied to the appropriate planning entity, there is no reason to maintain a requirement for an unaffiliated third party to perform a verification of a transmission planning analysis associated with the risk assessment. Instead of requiring planning entities be the third-party verifier, they should just perform the study under clearly defined requirements in a TPL standard and communicate this information to the Transmission Owner. It is also important to note the third party verifying the risk assessment for this physical security standard is not required to have expertise in that area according to this requirement. Additionally, the SDT should consider removing the Reliability Coordinator as a potential third-party verifier as that function does not perform the type of analysis being sought in this standard.

Additional Comment:

The analysis outlined in the CIP-014 standard is an evaluation of an extreme event and is based on transmission planning analysis. Currently, the existing TPL-001 standard requires the evaluation of extreme events, though, it is not specific to this particular substation outage analysis and corrective actions are not required for these events. Additionally, there are ongoing efforts to establish a separate standard to address the long-term planning analysis around extreme weather events. It would seem NERC and the industry are potentially missing an opportunity to consolidate requirements around the evaluation of extreme events better than what is currently provided for in the current construct of the existing and planned Reliability Standards. Consideration should be given by NERC to provide a better pathway to house long-term planning requirements around extreme event analysis within the TPL standards (not CIP) and specify the reliability analyses needed, the parameters for determining reliability, expectations for corrective actions, and the communication path from planning to owners and others with a reliability-related need for this information. The planning assessment/CAP required by TPL-001 is already required to be distributed to applicable owners. Clarifying the extreme event expectations in TPL-001 to specify the substation outage alluded to in CIP-014 is one pathway to better align standard requirements with the appropriate entity.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. The Standard Authorization Request (SAR), which defines the scope of work for the Project 2023-06 Drafting Team (DT) only lists Transmission Owners and Transmission Operators as Functional Entities to which the proposed standard should apply. Changes to existing Requirements R4 through R6, in CIP-014-3, is beyond the scope of Project 2023-06.

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

Comment

We suggest adding triggers or process diagram similar to PRC-004 for required actions if ownership changes.

R6.3: Request R6.3 allow for 90 days instead of 60 so proper work can be completed. With a more detailed analysis being required, there is a higher chance of disagreement with our third party reviewer, requiring more time needed for response.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see a flowchart at the end of the Technical Rationale document. Changes to, in CIP-014-3, existing Requirements R4 through R6 is beyond the scope of Project 2023-06.

Amy Wesselkamper - PNM Resources - Public Service Company of New Mexico - 3

Answer	
Document Name	

Comment

PNM and TNMP support EEI comments.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see response to EEI's comments.

Matt Carden - Southern Company - Southern Company Services, Inc. - 1

Answer	
Document Name	

Comment

Southern Company recommends swapping Requirement R3 and R4 chronologically. This follows a more logical approach of identifying the stations and responsibilities to perform the assessment in the first three requirements followed by an assessment methodology in R4 and the performance of an assessment in R5.

Southern Company recommends removing Requirement R6. With the understanding that this is not explicitly in scope of the current SAR, the added specificity of the proposed standard eliminates the reliability benefit of the third-party verifier. Additionally, based on a previous audit of CIP-014-3, Southern Company did not observe the Regional Entity take into consideration the review by the R2 third party verifier. If this is consistent across other Regional Entities, then an elimination of CIP-014-4 R6 may be appropriate due to the extra cost and the lack of a reliability benefit.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. While Requirement R3 and R4 were not swapped, they are re-worded in the latest draft CIP-014-4. Changes to, in CIP-014-3, existing Requirements R4 through R6, i.e., R6 in the draft CIP-014-4, is beyond the scope of Project 2023-06.

Devin Shines - PPL - Louisville Gas and Electric Co. - 1,3,5,6 - SERC,RF

Answer	
Document Name	
Comment	

LG&E/KU greatly appreciate the drafting team's willingness and effort to address concerns with the previous draft is greatly appreciated. The second draft makes substantial improvements while also accomplishing the objectives outlined in the SAR. While there are certain components of the standard that may be clarified and improved upon, the most crucial issues have been resolved.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

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

Answer	
Document Name	
Comment	

NA

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Rebika Yitna - Rebika Yitna On Behalf of: Roger Brand, MEAG Power, 3, 1; - Rebika Yitna

Answer	
Document Name	
Comment	

No additional comments

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Ben Hammer - Western Area Power Administration - 1

Answer	
Document Name	

Comment

WAPA recommends the SDT remove the third party verification Requirement R6. WAPA is concerned that this requirement holds an entity responsible for the actions of another organization, and creates the risk of non-compliances when a separate reviewer fails to complete their work on time.

While this elimination is not explicitly mentioned in the SAR, it is directly tied to the changes proposed in the SAR. The purpose of the third party verification goes away with the increased prescriptiveness of the risk assessment being made in the drafts of CIP-014-4. In addition, since the SAR indicates that industry was not implementing a consistent approach to the risk assessments, then that indicates the third party verifications were also proving to be of little value. This independent verification is a burdensome and costly endeavor that has not proven to be value-added. Planning this task with eligible vendors requires significant work to coordinate and thousands of dollars to complete. Given that the verifications exist solely to offer feedback on an approach which will no longer be required with the increased specificity in R3, then their removal would eliminate what has become an unnecessary administrative burden.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Changes to, in CIP-014-3, existing Requirements R4 through R6, i.e., R6 in the draft CIP-014-4, is beyond the scope of Project 2023-06.

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

Answer	
Document Name	

Comment

No additional comments.

Likes 0	
Dislikes 0	

Response

Thank you for your support.

Leshel Hutchings - AEP - 3

Answer	
Document Name	

Comment

AEP's Additional Comments:

1. There is a typo in R8 Section 8.3 which could be corrected in this revision. “Electricity Sector Information Sharing and Analysis Center (ES-ISAC)” should say “Electricity Information Sharing and Analysis Center (E-ISAC)”.
2. The level in the VRF/VSL justification does not match the VRF/VSL levels in the standard draft for R2 and R3 – these need to be aligned.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

1. The typo of E-ISAC in Requirement R8 Part 8.3 has been corrected.
2. This has been verified and the current revision should be correct.

Nikki Carson-Marquis - Nikki Carson-Marquis On Behalf of: Theresa Allard, Minnkota Power Cooperative Inc., 1; - Nikki Carson-Marquis

Answer	
Document Name	

Comment

MPC thanks the drafting team for their consideration and appreciates the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Ronald Hoover - Bonneville Power Administration - 1,3,5,6 - WECC

Answer	
Document Name	

Comment

BPA recognizes significant improvements with the current draft. With the exception of a few areas of clarity being needed, BPA believes we are on track to meet current NERC and FERC guidelines.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Joshua London - Eversource Energy - 1, Group Name Eversource

Answer	
Document Name	

Comment

R6.3: Eversource requests R6.3 allow for 90 days instead of 60 so proper work can be completed. With a more detailed analysis being required, there is a higher chance of disagreement with our third party reviewer, requiring more time needed for response.

Overall, Eversource appreciates the efforts of the drafting team and overall is in agreement with the current draft. Eversource's concerns of the use of the phrase "planned to be in service" in R1 is the only portion of the updated standard keeping the company from being in favor.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Changes to, in CIP-014-3, existing Requirements R4 through R6, i.e., R6 in the draft CIP-014-4, is beyond the scope of Project 2023-06. The language in Requirement R1 has been revised to provide additional clarity.

Matthew Nicklin - Southern Illinois Power Cooperative - 1,3,5 - SERC

Answer	
Document Name	

Comment

We would like to thank the SDT for it's hard work and allowing us to provide feedback.

Likes 0	
Dislikes 0	

Response

Thank you for your comment.

Jeffrey Streifling - NB Power Corporation - 1

Answer	
Document Name	

Comment

We suggest adding triggers or process diagram similar to PRC-004 for required actions if ownership changes.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see a flowchart at the end of the Technical Rationale document.

Erin Wilson - NB Power Corporation - New Brunswick Power Transmission Corporation - 5

Answer	

Document Name	
Comment	

We suggest adding triggers or process diagram similar to PRC-004 for required actions if ownership changes.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. Please see a flowchart at the end of the Technical Rationale document.

Brian Millard - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name TVA RBB

Answer	
Document Name	

Comment

N/A

Likes 0	
Dislikes 0	

Response

Kevin Conway - Western Power Pool - 4

Answer	
Document Name	

Comment

The Drafting Team's survey should be rethought going forward. Simple asking for a response that a requirement meets the SAR is lazy and requires the respondent to search the SAR for where the individual requirement may fit. The Drafting Team is encouraged to identify and map where a requirement is addressing each issue in the SAR. This will allow the respondent to provide much more specific feedback.

As in other standards that have specific applicability, all TOs should have to meet the R1 requirement every 36 months. They would then be able to determine their applicability to the other requirements if they meet the threshold.

TO's do not have transmission planning resources, and requirements that require the entity to do transmission studies, should be assigned to Transmission Planners or Planning Coordinators. If this is not done, the results of the effects of losing one or more transmission Facilities will be inconsistent and potentially could conflict with TPL-001 results.

Likes 0	
Dislikes 0	

Response

Thank you for your comment. References to applicable item(s) in the SAR has been added to each ‘Rationale for Requirement’ in the Technical Rationale document. The Standard Authorization Request (SAR), which defines the scope of work for the Project 2023-06 Drafting Team (DT) only lists Transmission Owners and Transmission Operators as Functional Entities to which the proposed standard should apply.