

## Consideration of Comments

**Project Name:** 2023-06 CIP-014 Risk Assessment Refinement | Standard Authorization Request  
**Comment Period Start Date:** 7/26/2023  
**Comment Period End Date:** 8/24/2023

There were 43 sets of responses, including comments from approximately 117 different people from approximately 92 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the [project page](#).

If you feel that your comment has been overlooked, let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, contact Director, Standards Development [Latrice Harkness](#) (via email) or at (404) 858-8088.

## Questions

1. [Do you agree with the proposed scope as described in the Project 2023-06 CIP-014 SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.](#)
2. [Provide any additional comments for the SAR drafting team to consider, if desired.](#)

## Industry Segments:

- 1 — Transmission Owners
- 2 — RTOs, ISOs
- 3 — Load-serving Entities
- 4 — Transmission-dependent Utilities
- 5 — Electric Generators
- 6 — Electricity Brokers, Aggregators, and Marketers
- 7 — Large Electricity End Users
- 8 — Small Electricity End Users
- 9 — Federal, State, Provincial Regulatory or other Government Entities
- 10 — Regional Reliability Organizations, Regional Entities

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Midcontinent ISO, Inc.	Bobbi Welch	2	MRO,RF,SERC	ISO/RTO Council Standards Review Committee 2023-06 CIP-014 Risk Assessment SAR	Kennedy Meier	Electric Reliability Council of Texas, Inc.	2	Texas RE
					Bobbi Welch	MISO	2	RF
					Gregory Campoli	New York Independent System Operator	2	NPCC
					Elizabeth Davis	PJM	2	RF
					Charles Yeung	SPP	2	MRO
Tacoma Public Utilities (Tacoma, WA)	Jennie Wike	1,3,4,5,6	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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Ozan Ferrin	Tacoma Public Utilities (Tacoma, WA)	5	WECC
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,RF,SERC,Texas RE,WECC	ACES Collaborators	Bob Soloman	Hoosier Energy Electric Cooperative	1	RF
					Jennifer Bray	Arizona Electric Power Cooperative, Inc.	1	WECC
					Nick Fogleman	Prairie Power, Inc.	1,3	SERC
					Marcus Perkins	Southern Maryland Electric Cooperative	3	RF
MRO	Jou Yang	1,2,3,4,5,6	MRO	MRO NSRF	Bobbi Welch	Midcontinent ISO, Inc.	2	MRO
					Chris Bills	City of Independence, Power and Light Department	5	MRO
					Fred Meyer	Algonquin Power Co.	3	MRO

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					Christopher Bills	City of Independence Power & Light	3,5	MRO
					Larry Heckert	Alliant Energy Corporation Services, Inc.	4	MRO
					Marc Gomez	Southwestern Power Administration	1	MRO
					Matthew Harward	Southwest Power Pool, Inc. (RTO)	2	MRO
					Bryan Sherrow	Board of Public Utilities	1	MRO
					Terry Harbour	Berkshire Hathaway Energy - MidAmerican Energy Co.	1	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Jamison Cawley	Nebraska Public Power District	1,3,5	MRO
					Seth	Muscatine	1,3,5,6	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Shoemaker	Power & Water		
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Shonda McCain	Omaha Public Power District	6	MRO
					George E Brown	Pattern Operators LP	5	MRO
					George Brown	Acciona Energy USA	5	MRO
					Jaimin Patel	Saskatchewan Power Cooperation	1	MRO
					Kimberly Bentley	Western Area Power Administration	1,6	MRO
					Jay Sethi	Manitoba Hydro	1,3,5,6	MRO
					Michael Ayotte	ITC Holdings	1	MRO
FirstEnergy - FirstEnergy Corporation	Mark Garza	1,3,4,5,6		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Mark Garza	FirstEnergy-FirstEnergy	1,3,4,5,6	RF
					Stacey Sheehan	FirstEnergy - FirstEnergy Corporation	6	RF
Pacific Gas and Electric Company	Michael Johnson	1,3,5	WECC	PG&E All Segments	Marco Rios	Pacific Gas and Electric Company	1	WECC
					Sandra Ellis	Pacific Gas and Electric Company	3	WECC
					Frank Lee	Pacific Gas and Electric Company	5	WECC
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Matt Carden	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Jim Howell, Jr.	Southern Company - Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	NPCC RSC	Gerry Dunbar	Northeast Power Coordinating Council	10	NPCC
					Alain Mukama	Hydro One Networks, Inc.	1	NPCC
					Deidre Altobell	Con Edison	1	NPCC
					Jeffrey Streifling	NB Power Corporation	1	NPCC
					Michele Tondalo	United Illuminating Co.	1	NPCC
					Stephanie Ullah-Mazzuca	Orange and Rockland	1	NPCC
					Michael Ridolfino	Central Hudson Gas &	1	NPCC



Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Electric Corp.		
					Randy Buswell	Vermont Electric Power Company	1	NPCC
					James Grant	NYISO	2	NPCC
					John Pearson	ISO New England, Inc.	2	NPCC
					Harishkumar Subramani Vijay Kumar	Independent Electricity System Operator	2	NPCC
					Randy MacDonald	New Brunswick Power Corporation	2	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					David Burke	Orange and Rockland	3	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Salvatore	New York	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Spagnolo	Power Authority		
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					David Kwan	Ontario Power Generation	4	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	1	NPCC
					Glen Smith	Entergy Services	4	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
					ALAN	New York	10	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					ADAMSON	State Reliability Council		
					David Kiguel	Independent	7	NPCC
					Joel Charlebois	AESI	7	NPCC
					Joshua London	Eversource Energy	1	NPCC
Western Electricity Coordinating Council	Steven Rueckert	10		WECC CIP	Steve Rueckert	WECC	10	WECC
					Morgan King	WECC	10	WECC
					Deb McEndaffer	WECC	10	WECC
					Tom Williams	WECC	10	WECC

<b>1. Do you agree with the proposed scope as described in the Project 2023-06 CIP-014 SAR? If you do not agree, or if you agree but have comments or suggestions for the project scope please provide your recommendation and explanation.</b>	
<b>Tony Eddleman - Nebraska Public Power District - 1,3,5</b>	
<b>Answer</b>	No
<b>Document Name</b>	
<b>Comment</b>	
Due to the critical interdependency between requirement 1 and requirement 2, requirement 2 should be added to the project scope for the drafting team.	
Likes	0
Dislikes	0
<b>Response</b>	
The team agrees that clarity regarding the timing of transmission projects included in the risk assessment is needed. The team will also provide clarity on when the 30 (or 60) months clock for the next subsequent risk assessment starts, relative to completion of the R1 risk assessment and the R2 third-party review. The team does not propose to add R2 to the SAR, but will continue to evaluate the need for revisions to R1.	
<b>Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power</b>	
<b>Answer</b>	No
<b>Document Name</b>	
<b>Comment</b>	
Tacoma Power endorses the comments from MRO NSRF.	
In addition to the MRO NSRF comments, Tacoma Power does not agree with the description in the Cost Impact Assessment section of the SAR. Specifically, the statement that “cost impacts for the proposed changes to CIP-014-3 are expected to be minimal.” The cost impacts are significant for Detail 5, “Revise the risk assessment and 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.” Tacoma Power recommends revising the cost impact section of the SAR to recognize that the work necessary to implement Detail 5 would be significant and may result in additional applicable substations.

The SAR is also not clear as to how Detail 5 would impact the Section 4.1.1 applicable facility determination. There are facilities that do not meet the Section 4.1.1 applicability criteria when evaluated separately, but may meet that criteria if Detail 5 is applied.

Tacoma Power recommends that the SAR scope include an additional Detail to clarify the evidence required to demonstrate that an entity does not have applicable facilities. Throughout the ERO Enterprise, there is inconsistency on whether entities with a null list of applicable facilities are required to comply with CIP-014 R1-R3.

Likes 0

Dislikes 0

**Response**

The team agrees that clarification on the cost impact statement in the SAR was needed. Language was revised in the SAR to clarify there may be cost impacts for revisions to the R1 risk assessment as well as potential downstream costs for additionally identified critical sites.

The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

The team will consider revisions to clarify what is expected during the R1 risk assessment when an entity has no applicable facilities.

**Stephen Stafford - Georgia Transmission Corporation - 1 - SERC**

**Answer**

No

**Document Name**

**Comment**

Items 1 – 4 in the Project Scope section of the SAR suggest the standard should be modified to clarify “methods for studying”, “study period”, “frequency of study”, “base cases”, “study decisions”, and other terminology that suggests a planning function is being performed. CIP-014 is only applicable to the owner functional entities who do not perform planning analyses. It does not seem appropriate to add planning analysis requirements in the CIP-014 standard when it is not applicable to planning entities.

Likes 0

Dislikes 0

**Response**

The scope of the SAR is to revise and add clarity to existing R1 requirement expectations as the applicable entities for CIP-014 have already been approved and have risk assessment requirements implemented.

**Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name** ISO/RTO Council Standards Review Committee 2023-06 CIP-014 Risk Assessment SAR

**Answer**

No

**Document Name**

**Comment**

The **ISO/RTO Council (IRC) Standards Review Committee (SRC)**[\[1\]](#) appreciates the opportunity to comment. The SRC agrees that additional clarity and specificity will increase the efficacy of CIP-014. In support of that objective, the SRC recommends that the scope be revised to direct the drafting team to clarify the following areas of ambiguity.

- For a transmission station or substation connecting to a collector bus for a generation plant, clarify whether the collector bus is still not considered a Transmission Facility for purposes of Applicability criteria 4.1.1.1 and 4.1.1.2 if the collector bus is the Point of Interconnection for the generation plant.
- For Applicability criterion 4.1.1.2, clarify whether the Weight Value per Line is applied per transmission line or per transmission circuit. For example, clarify whether a double-circuit 345-kV line has a weight value of 2600 or 1300.
- Clarify the extent to which radial facilities qualify as Transmission Facilities for purposes of the Applicability criteria for CIP-014-3. The Guidelines and Technical Basis for CIP-014-3 (page 21 of the standard) indicates that the Applicability section of CIP-014-3 mirrors the bright line criteria for Medium Impact Transmission Facilities under CIP-002-5.1a. Page 27 of CIP-002-5.1a, in turn, indicates that Criterion 2.5 for identifying Medium Impact Transmission Facilities excludes “radial facilities that would only provide

support for single generation facilities.” It is not clear how this exclusion fits in with the Applicability criteria of CIP-014-3. Specifically, it is not clear if these radial facilities should be included in the determination of how many stations or substations a given station or substation connects to, and it is not clear if these radial facilities should be assigned a weight value as incoming or outgoing BES Transmission Lines that connect to another Transmission station or substation.

- Clarify how the exclusion for “radial facilities that would only provide support for single generation facilities” (discussed above) interacts with the statement on page 23 of CIP-002-5.1a that “[w]hen the drafting team uses the term ‘Facilities,’ there is some latitude to Responsible Entities to determine included Facilities,” and with CIP-014-3 Requirement R2, Part 2.3’s authorization for TOs to document the technical basis for not modifying an identification in accordance with a recommendation from an unaffiliated verifying entity. Specifically, clarify how much latitude TOs have to interpret the exclusion for “radial facilities that would only provide support for single generation facilities.”

[\[1\]](#) For purposes of these comments, the IRC SRC includes the following entities: ERCOT, MISO, NYISO, PJM and SPP.

Likes 0

Dislikes 0

**Response**

The team is not changing the scope to modify the applicability section criteria, including common criteria between CIP-002 and CIP-014. The team will include changes to the risk assessment and provide more clarity on others areas (such as physical proximity) to address the objectives of the SAR.

The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

**Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2**

Answer

No

Document Name

Comment

ERCOT joins the comments submitted by the ISO/RTO Council (IRC) Standards Review Committee (SRC) and adopts them as its own.	
Likes	0
Dislikes	0
<b>Response</b>	
Thank you for your comments. See the response to the ISO/RTO Council (IRC) Standards Review Committee (SRC).	
<b>Jou Yang - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
<p>The MRO NSRF agrees with the scope of the SAR as having identified the aspects of CIP-014 R1 that require clarification, but disagrees with some of the subsequent detailed instructions to the drafting team as follows:</p> <p>Detail 1, please replace the final bolded item “BPS” with “BES.” Industry has already identified all BES Transmission Elements when the term was redefined for 2014. There are no such defined lists of BPS equipment. Applicability Section 4.1.1 and parts already provide such specificity as has already been validated as sufficient by the NERC report filed with FERC. There is no justification to arbitrarily reference a broader BPS within this standard, and Section 4.1.1 renders the change moot.</p> <p>Detail 3 takes the general guidance of Scope item 3 but specifies “defining ‘inoperable’ or ‘damaged’ substations”, which is inconsistent with Scope item 4 that will require simulating complete loss. The sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear.” binds the drafting team to maintain and define language inconsistent with Scope item 4 and should be removed. Removing this sentence would free the drafting team to replace this language with something like “destroyed” which could then be defined in accordance with Scope item 4.</p> <p>Detail 5 can provide a list of items requiring consideration, but it must be made clear to the drafting team that while these items must be considered, they do not necessarily have to be modeled as also lost if an entity’s evaluation cites mitigating circumstances such as the adjacent or line-of-sight Facility already having or implementing security measures to counter these threats before the next risk assessment is due (consistent with Scope item 2). Any items listed for required consideration should be sufficiently defined and limited so</p>	



as not to require the equivalent performance of a full R4 threat assessment.	
Likes 1	Tacoma Public Utilities (Tacoma, WA), 1,3,4,5,6, Wike Jennie
Dislikes 0	
<b>Response</b>	
We agree with replacing “BPS” with “BES” in item 1 since “BES” is a defined and well understood term that is appropriately applied in the context of CIP-014.	
The team plans to review usage of the terms ‘inoperable’ and/or ‘damaged’ in light of revising the risk assessment to simulate the complete loss of a Transmission station or Transmission substation that includes the simultaneous loss of all station elements and does not rely on local system protection for relay clearance (as noted in item 4). To allow for this, and align with item 4, the sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear” will be re-worded to “Clarify the how the terms “inoperable” and “damaged” should be reflected in the risk assessment.”	
The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.	
<b>Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
FirstEnergy supports the scope of the SAR and further supports EEI comments.	
Likes 0	
Dislikes 0	
<b>Response</b>	

Thank you for your comments. See the response to EEI.	
<b>Jennifer Bray - Arizona Electric Power Cooperative, Inc. - 1</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
<p>AEPC has signed on to ACES comments below:</p> <p>Every critical station within the scope of CIP-014 poses different challenges and risks to consider. Each entity has different people, constraints (physical, technological, electrical, etc.), and risks; therefore, the expectation that entities would have “reasonably consistent” approaches to CIP-014 is not a reasonable expectation.</p> <p>This SAR’s proposed changes are similar to previous changes to the CIP standards, such as CIP-002-3 (risk based) versus CIP-002-5.1a (bright line). This SAR should seek to establish a minimum baseline of risks/risk attributes that NERC, FERC, and the industry believe need to be evaluated to have a more “reasonably consistent” approach. Establishing a baseline, such as logging and monitoring in CIP-007, or bright line in CIP-002, would provide some of the consistency the SAR proposes to provide, but each approach may still be different. If the Standards Drafting Team (SDT) were to add baseline risks for consideration, they should not be overly prescriptive, rather they should provide a minimum list of risks to consider and any exclusions to allow the entity flexibility in its approach.</p> <p>The cost impact cannot be overlooked in the SAR. If a set of risk criteria is established as a result of this project and an entity did not previously consider one or more of those risk, a control would need to be created to mitigate the risk, which could come with a cost. The proposed changes to CIP-014 will require each entity within the scope to rewrite its CIP-014 program and reevaluate each risk assessment, which could also come with a cost.</p>	
Likes	0
Dislikes	0
<b>Response</b>	
<p>The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission</p>	

stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

The team will also revise the SAR to clarify specific requirement language regarding evaluating instability, uncontrolled separation, and Cascading within an Interconnection (by conducting steady-state and dynamic studies) while allowing for entity-specific flexibility in the development of study methods.

The team agrees that clarification on the cost impact statement in the SAR was needed. Language was revised in the SAR to clarify there may be cost impacts for revisions to the R1 risk assessment as well as potential downstream costs for additionally identified critical sites.

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

<b>Answer</b>	Yes
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<b>Document Name</b>	
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<b>Comment</b>
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While we agree that the identification of applicable facilities criteria could benefit from more clarity on the initiating event(s) triggering the resulting consequence “...that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.”, changes, as proposed in the SAR, will impose a tremendous effort on entities to achieve compliance.

Likes 0	
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Dislikes 0	
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<b>Response</b>
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While the team is not expanding the scope of the SAR to modify the applicability section, the team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

The team plans to review usage of the terms ‘inoperable’ and/or ‘damaged’ in light of revising the risk assessment to simulate the complete loss of a Transmission station or Transmission substation that includes the simultaneous loss of all station elements and does not rely on local system protection for relay clearance (as noted in item 4). To allow for this, and align with item 4, the sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear” will be re-worded to “Clarify the how the terms “inoperable” and “damaged” should be reflected in the risk assessment.”

The draft with proposed changes to CIP-014 will be shared with NERC compliance to provide feedback on if the team’s proposed requirements and measures are clear and auditable.

**April Ford - Southern Indiana Gas and Electric Co. - 3,5,6 - RF**

<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Southern Indiana Gas and Electric Company d/b/a CenterPoint Energy Indiana (SIGE) agrees with the proposed scope of the SAR.	
Likes	0
Dislikes	0

**Response**

Thank you for the comment.

**Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE**

<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	

Oncor encourages NERC to consider the vast diversity of the Bulk Power Systems owned and operated by the Registered Entities to which the new CIP-014 would apply (*e.g.*, the varied operating environments or different market structures in which those Registered Entities do business) and to acknowledge in the revised Standard the possibility that the criteria for the required risk assessment may be revised as needed to enable the affected Registered Entity to properly assess its Transmission stations and Transmission Substations.

Likes	0
Dislikes	0
<b>Response</b>	
The team will continue to review ERO-wide differences between entities during the standards development process, and consider all comments received from each period as well as through discussions during team meetings.	
<b>Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&amp;E All Segments</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
<p>PG&amp;E has the following input related to the Detailed Description in the SAR starting on page 3:</p> <p><b>For Item 1;</b> PG&amp;E concurs and supports the clarification of the risk assessment methods for studying instability, uncontrolled separation, and Cascading. PG&amp;E also recommends that as part of the clarification, it is important for NERC to consider that registered entities will need to evaluate each broad type of stability based on their regional requirements. For instance, PG&amp;E is currently following the TPL 001-WECC-CRT-3.2 criterion for voltage and frequency performance to assess the results of the Transient Stability analysis.</p> <p><b>For Item 2;</b> PG&amp;E agrees that the statement “including only the projects that are appropriate to the periodicity of the entity’s risk assessment studies” should be clarified, as the existing language could have different interpretations.</p> <p><b>For Item 3;</b> PG&amp;E has no comment.</p> <p><b>For Item 4;</b> PG&amp;E supports the input has a comment regarding the following statement “it is not clear that the risk assessment requires registered entities to use models that correlate to periods of high flows or high stress on their system”. Since each region experiences different high flow patterns and stressed conditions, PG&amp;E suggests that NERC provide clarifications and guidelines for defining the high stressed scenarios but allows entities to define their scenarios based on their unique system conditions and their respective region.</p> <p><b>For Item 5;</b> PG&amp;E encourages clarification regarding what physically adjacent elements shall be considered within the risk assessment. In addition, if a substation is identified as critical based on the study and related substation (asset) is not owned by the registered entity that performed the study, clarification should be provided regarding the responsibilities between that registered entity and the other asset owner.</p>	

**For the Cost Impact Assessment on page 5**, PG&E provides the following; PG&E understands that the NERC proposed changes are targeting to add clarity to the current standard and not changing the existing requirements. However, implementing the proposed clarifications may result in more substations requiring security upgrades and that would impact the associated costs.

Likes 0

Dislikes 0

**Response**

The team will also revise the SAR to clarify specific requirement language regarding evaluating instability, uncontrolled separation, and Cascading within an Interconnection (by conducting steady-state and dynamic studies) while allowing for entity-specific flexibility in the development of study methods.

The team agrees that clarity regarding the timing of transmission projects included in the risk assessment is needed. The team will also provide clarity on when the 30 (or 60) months clock for the next subsequent risk assessment starts, relative to completion of the R1 risk assessment and the R2 third party review. The team does not propose to add R2 to the SAR, but will continue to evaluate the need for revisions to R1.

The team removed the sentence regarding high flows or high stress. The team will add clarity to the risk assessment requirement regarding what are appropriate study decisions and what should be considered for the selection of model cases and any applied scenario conditions.

The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

The team agrees that clarification on the cost impact statement in the SAR was needed. Language was revised in the SAR to clarify there may be cost impacts for revisions to the R1 risk assessment as well as potential downstream costs for additionally identified critical sites.

**Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC**

<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
<p>While we agree that the identification of applicable facilities criteria could benefit from more clarity on the initiating event(s) triggering the resulting consequence "...that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.", changes, as proposed in the SAR, will impose a tremendous effort on entities to achieve compliance.</p>	
Likes 0	
Dislikes 0	
<b>Response</b>	
<p>The team plans to review usage of the terms 'inoperable' and/or 'damaged' in light of revising the risk assessment to simulate the complete loss of a Transmission station or Transmission substation that includes the simultaneous loss of all station elements and does not rely on local system protection for relay clearance (as noted in item 4). To allow for this, and align with item 4, the sentence "Criteria should include defining "inoperable" or "damaged" substations such that the intent of the risk assessment is clear" will be re-worded to "Clarify the how the terms "inoperable" and "damaged" should be reflected in the risk assessment."</p> <p>While the team is not expanding the scope of the SAR to modify the applicability section, the team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report 'Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System' filed in response to a FERC directive.</p> <p>The draft with proposed changes to CIP-014 will be shared with NERC compliance to provide feedback on if the team's proposed requirements and measures are clear and auditable.</p>	
<b>Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE</b>	
<b>Answer</b>	Yes

<b>Document Name</b>	
<b>Comment</b>	
CenterPoint Energy Houston Electric, LLC (CEHE) agrees with the proposed scope of the SAR.	
Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you for your comment.	
<b>Jay Sethi - Manitoba Hydro - 1,3,5,6 - MRO</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
<p>Manitoba Hydro agrees with the scope of the SAR. Further clarification of CIP-014 R1 as proposed in the SAR will help the industry as a whole. Manitoba Hydro is requesting additionally that the SAR provide clarity on whether past studies can be relied upon if there are no material changes in the network since the last CIP-014 assessment, provided that the Transmission Owner has performed an acceptable risk assessment which meets the requirements identified in the scope of this SAR? This would reduce study burden on industry; especially on entities studying every 30 months.</p> <p>Manitoba Hydro also has some comments relating to the detailed description items and suggests the following changes:</p> <p>In detailed description number 1, replace the term “BPS” with “BES” which is well defined and for which a well established inventory of elements exists.</p> <p>In detailed description number 3, it takes the general guidance of Scope item 3 but specifies “defining ‘inoperable’ or ‘damaged’ substations”, which is inconsistent with Scope item 4 that will require simulating complete loss. The sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear.” binds the drafting team to maintain and define language inconsistent with Scope item 4 and should be removed. The standard drafting team should be free to review the option of changing the wording to add clarity, as well as the option to further define the terms.</p>	



In detailed description number 5, it can provide a list of items requiring consideration, but it must be made clear to the drafting team that while these items must be considered, they do not necessarily have to be modeled as also lost if an entity’s evaluation cites mitigating circumstances such as the adjacent or line-of-sight Facility already having or implementing security measures to counter threats before the next risk assessment is due (consistent with Scope item 2). Any items listed for required consideration should be sufficiently defined and limited so as not to require the equivalent performance of a full R4 threat assessment.

Likes 0

Dislikes 0

**Response**

We agree with replacing “BPS” with “BES” in item 1 since “BES” is a defined and well understood term that is appropriately applied in the context of CIP-014.

The team plans to review usage of the terms ‘inoperable’ and/or ‘damaged’ in light of revising the risk assessment to simulate the complete loss of a Transmission station or Transmission substation that includes the simultaneous loss of all station elements and does not rely on local system protection for relay clearance (as noted in item 4). To allow for this, and align with item 4, the sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear” will be re-worded to “Clarify the how the terms “inoperable” and “damaged” should be reflected in the risk assessment.”

The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

**John Pearson - ISO New England, Inc. - 2**

**Answer**

Yes

**Document Name**

**Comment**

ISO New England supports the changes to make the standard result in more uniform determinations that will most appropriately identify

critical infrastructure and evaluate whether the physical security protection requirements are adequate to address the risks associated with physical attacks on Bulk Power System (BPS) Facilities. The owners of the BPS Facilities are the most appropriate entities to make initial determinations and appropriate identification.

Likes 0

Dislikes 0

**Response**

Thank you for your comment.

**Michael Jones - National Grid USA - 1,3,5**

**Answer**

Yes

**Document Name**

**Comment**

RE: Project Scope Item 2: Please consider adding to the Project Scope and Detailed Description that the amount of time between risk assessments should be clarified. Requirement R1 Part 1.1 of CIP-014-3 states “Subsequent risk assessments shall be performed: At least once every 30 calendar months... or, At least once every 60 calendar months... (as verified according to Requirement R2)” This could be interpreted as the 30 or 60 calendar months clock for the next subsequent risk assessment starts when Requirement R2 is completed, i.e., up to 90 + 60 days after Requirement R1 was completed. This could potentially also be interpreted as the 30 or 60 calendar months clock for the next subsequent risk assessment starts once Requirement R1 has been completed. Please consider that the SAR should specifically give the drafting team the ability to resolve this issue.

Likes 0

Dislikes 0

**Response**

The team agrees that clarity regarding the timing of transmission projects included in the risk assessment is needed. The team will also provide clarity on when the 30 (or 60) months clock for the next subsequent risk assessment starts, relative to completion of the R1 risk assessment and the R2 third party review. The team does not propose to add R2 to the SAR, but will continue to evaluate the need for revisions to R1.

<b>Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
<p>EEI supports adding requirements that provide additional clarity to existing risk assessment methods for studying instability, uncontrolled separation, and cascading. However, we would not support changes to requirements that resulted in modifications that deviated from the clearly defined project scope as contained in this SAR or added prescriptive requirements that did not consider regional differences and geography. Standards should be flexible, and risk based.</p> <p>EEI asks for clarity to Item 3 in the SAR Project Scope where it uses the term “adequacy”. As currently written this Item could be understood to require changes to CIP-014 that would require the development of prescriptive requirements for both documentation and entity studies that could be interpreted as deviating from the current Risk Based Reliability Standard processes.</p> <p>EEI also requests clarity on the intended scope of Item 5 in the SAR Project Scope. Specifically, clarity is needed as it relates to Transmission stations or substations of differing ownership, as well as transmission stations or substations within line-of-site to each other. However, it should be clear that responsible entities need the authority to request certain information from the responsible entities identified in Item 5, to conduct their CIP-014 studies (i.e., models, actual clearing times, etc.).</p>	
Likes	0
Dislikes	0
<b>Response</b>	
<p>The team will revise the SAR to clarify specific requirement language regarding evaluating instability, uncontrolled separation, and Cascading within an Interconnection (by conducting steady-state and dynamic studies) while allowing for entity-specific flexibility in the development of study methods.</p> <p>The team agrees that the revisions to R1 should not be overly prescriptive in the outcome of study decisions and documentation. The approach by the team will consider entity flexibility and increased clarity on expectations related to Item 3.</p> <p>The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to</p>	

account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report 'Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System' filed in response to a FERC directive.

**Alan Kloster - Evergy - 1,3,5,6 - MRO**

**Answer** Yes

**Document Name**

**Comment**

Evergy supports and incorporates by reference the comments of the Edison Electric Institute (EEI) for question #1.

Likes 0

Dislikes 0

**Response**

Thank you for your comment. See response to EEI.

**Clay Walker - Cleco Corporation - 1,3,5,6 - SERC**

**Answer** Yes

**Document Name**

**Comment**

Cleco support the comments provided by EEI.

Likes 0

Dislikes 0

**Response**

Thank you for your comment. See response to EEI.

**Richard Vendetti - NextEra Energy - 5**

<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
<p>NEE is in agreement with EEI's comments.</p> <p>EEI supports adding requirements that provide additional clarity to existing risk assessment methods for studying instability, uncontrolled separation, and cascading. However, we would not support changes to requirements that resulted in modifications that deviated from the clearly defined project scope as contained in this SAR or added prescriptive requirements that did not consider regional differences and geography. Standards should be flexible, and risk based.</p> <p>EEI asks for clarity to Item 3 in the SAR Project Scope where it uses the term "adequacy". As currently written this Item could be understood to require changes to CIP-014 that would require the development of prescriptive requirements for both documentation and entity studies that could be interpreted as deviating from the current Risk Based Reliability Standard processes.</p> <p>EEI also requests clarity on the intended scope of Item 5 in the SAR Project Scope. Specifically, clarity is needed as it relates to Transmission stations or substations of differing ownership, as well as transmission stations or substations within line-of-site to each other. However, it should be clear that responsible entities need the authority to request certain information from the responsible entities identified in Item 5, to conduct their CIP-014 studies (i.e., models, actual clearing times, etc.).</p>	
Likes	0
Dislikes	0
<b>Response</b>	
Thank you for your comment. See response to EEI.	
<b>Ellese Murphy - Duke Energy - 1,3,5,6 - MRO,WECC,Texas RE,SERC,RF</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	

Duke Energy supports EEI's comments.	
Likes	0
Dislikes	0
<b>Response</b>	
Thank you for your comment. See response to EEI.	
<b>Rachel Coyne - Texas Reliability Entity, Inc. - 10</b>	
Answer	Yes
Document Name	
<b>Comment</b>	
Texas RE supports this project to ensure adequacy and consistency in the CIP-014 approach. Texas RE recommends the SAR indicate whether the terms “inoperable” or “damaged” will be defined in the NERC Glossary.	
Likes	0
Dislikes	0
<b>Response</b>	
The team plans to review usage of the terms ‘inoperable’ and/or ‘damaged’ in light of revising the risk assessment to simulate the complete loss of a Transmission station or Transmission substation that includes the simultaneous loss of all station elements and does not rely on local system protection for relay clearance (as noted in item 4). To allow for this, and align with item 4, the sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear” will be re-worded to “Clarify the how the terms “inoperable” and “damaged” should be reflected in the risk assessment.”	
<b>Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5</b>	
Answer	Yes
Document Name	
<b>Comment</b>	

While we agree that the identification of applicable facilities criteria could benefit from more clarity on the initiating event(s) triggering the resulting consequence “...that if rendered inoperable or damaged as a result of a physical attack could result in instability, uncontrolled separation, or Cascading within an Interconnection.”, changes, as proposed in the SAR, will impose a tremendous effort on entities to achieve compliance.

Likes 0

Dislikes 0

**Response**

The team plans to review usage of the terms ‘inoperable’ and/or ‘damaged’ in light of revising the risk assessment to simulate the complete loss of a Transmission station or Transmission substation that includes the simultaneous loss of all station elements and does not rely on local system protection for relay clearance (as noted in item 4). To allow for this, and align with item 4, the sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear” will be re-worded to “Clarify the how the terms “inoperable” and “damaged” should be reflected in the risk assessment.”

The draft with proposed changes to CIP-014 will be shared with NERC compliance to provide feedback on if the team’s proposed requirements and measures are clear and auditable.

**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**

ACES agrees with the scope of the SAR, with the following comments:

Every critical station within the scope of CIP-014 poses different challenges and risks to consider. Each entity has different people, constraints (physical, technological, electrical, etc.), and risks; therefore, the expectation that entities would have “reasonably consistent” approaches to CIP-014 is not a reasonable expectation.

This SAR’s proposed changes are similar to previous changes to the CIP standards, such as CIP-002-3 (risk based) versus CIP-002-5.1a (bright line). This SAR should seek to establish a minimum baseline of risks/risk attributes that NERC, FERC, and the industry believe need to be evaluated to have a more “reasonably consistent” approach. Establishing a baseline, such as logging and monitoring in CIP-007, or

bright line in CIP-002, would provide some of the consistency the SAR proposes to provide, but each approach may still be different. If the Standards Drafting Team (SDT) were to add baseline risks for consideration, they should not be overly prescriptive, rather they should provide a minimum list of risks to consider and any exclusions to allow the entity flexibility in its approach.

The cost impact cannot be overlooked in the SAR. If a set of risk criteria is established as a result of this project and an entity did not previously consider one or more of those risk, a control would need to be created to mitigate the risk, which could come with a cost. The proposed changes to CIP-014 will require each entity within the scope to rewrite its CIP-014 program and reevaluate each risk assessment, which could also come with a cost.

Likes	0
Dislikes	0

**Response**

The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

The team is not changing the scope to modify the applicability section criteria, including common criteria between CIP-002 and CIP-014. The team will include changes to the risk assessment and provide more clarity on others areas (such as physical proximity) to address the objectives of the SAR.

The team agrees that clarification on the cost impact statement in the SAR was needed. Language was revised in the SAR to clarify there may be cost impacts for revisions to the R1 risk assessment as well as potential downstream costs for additionally identified critical sites.

**Dwanique Spiller - Berkshire Hathaway - NV Energy - 5**

Answer	Yes
Document Name	

**Comment**



NV Energy agrees with the scope of the SAR as having identified the aspects of CIP-014 R1 that require clarification, but disagrees with some of the subsequent detailed instructions to the drafting team as follows:

Detail 1, please replace the final bolded item “BPS” with “BES.” Industry has already identified all BES Transmission Elements when the term was redefined for 2014. There are no such defined lists of BPS equipment. Applicability Section 4.1.1 and parts already provide such specificity as has already been validated as sufficient by the NERC report filed with FERC. There is no justification to arbitrarily reference a broader BPS within this standard, and Section 4.1.1 renders the change moot.

Detail 3 takes the general guidance of Scope item 3 but specifies “defining ‘inoperable’ or ‘damaged’ substations”, which is inconsistent with Scope item 4 that will require simulating complete loss. The sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear.” binds the drafting team to maintain and define language inconsistent with Scope item 4 and should be removed. Removing this sentence would free the drafting team to replace this language with something like “destroyed” which could then be defined in accordance with Scope item 4.

Detail 5 can provide a list of items requiring consideration, but it must be made clear to the drafting team that while these items must be considered, they do not necessarily have to be modeled as also lost if an entity’s evaluation cites mitigating circumstances such as the adjacent or line-of-sight Facility already having or implementing security measures to counter these threats before the next risk assessment is due (consistent with Scope item 2). Any items listed for required consideration should be sufficiently defined and limited so as not to require the equivalent performance of a full R4 threat assessment.

Likes 0

Dislikes 0

**Response**

We agree with replacing “BPS” with “BES” in item 1 since “BES” is a defined and well understood term that is appropriately applied in the context of CIP-014.

The team plans to review usage of the terms ‘inoperable’ and/or ‘damaged’ in light of revising the risk assessment to simulate the complete loss of a Transmission station or Transmission substation that includes the simultaneous loss of all station elements and does not rely on local system protection for relay clearance (as noted in item 4). To allow for this, and align with item 4, the sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear” will be re-worded to “Clarify the how the terms “inoperable” and “damaged” should be reflected in the risk assessment.”

The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

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

**Answer** Yes

**Document Name**

**Comment**

Southern Company agrees with the submitted comments by EEI.

Likes 0

Dislikes 0

**Response**

Thank you for your comment. See response to EEI.

**Daniel Gacek - Exelon - 1,3**

**Answer** Yes

**Document Name**

**Comment**

Exelon generally supports the proposed scope of this project, and we support the comments submitted by the EEI.

We offer the following additional comments to help refine the scope.

For Item 4, there is inconsistency between the Project Scope section and the Detailed Description, specifically in the Project Scope section it states “simultaneous loss of all station elements and does not rely on local system protection for relay clearance”, however in the

Detailed Description section it seems to leave open to the SDT to determine how to resolve the initiating event assumptions.

The word simultaneous in the Project Scope section is also potentially problematic. In dynamic studies there may be a significant difference between literally simultaneous and a couple cycles (milliseconds) of delay. Some physical threats can result in simultaneous loss of station elements, other physical threats may result in delay between loss of station elements. Modifications to the standard should include the latitude for the planning analysis to align with the physical threats with regard to delay or lack of delay between the loss of substation elements.

For Item 5, similar to Item 4, the standard should include the latitude for the planning analysis to align with the identified physical threats with regard to delay or lack of delay between the loss of substation elements.

Likes 0

Dislikes 0

**Response**

The team plans to review usage of the terms ‘inoperable’ and/or ‘damaged’ in light of revising the risk assessment to simulate the complete loss of a Transmission station or Transmission substation that includes the simultaneous loss of all station elements and does not rely on local system protection for relay clearance (as noted in item 4). To allow for this, and align with item 4, the sentence “Criteria should include defining “inoperable” or “damaged” substations such that the intent of the risk assessment is clear” will be re-worded to “Clarify the how the terms “inoperable” and “damaged” should be reflected in the risk assessment.”

The team will consider other methods to evaluate a physical attack that are appropriate for the R1 risk assessment and may leverage the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

**Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6**

**Answer**

Yes

**Document Name**

**Comment**

AZPS agrees with EEI in supporting the development of standards which provide clarity to existing risk assessment methods for studying instability, uncontrolled separation, and cascading while maintaining standards that are flexible and risk based. In regard to item 5, AZPS

would also like clarity as to the intended scope of changes relating to transmission substations within close physical proximity/line of sight and the required information sharing between entities when differing ownership is a factor.

Likes 0

Dislikes 0

**Response**

The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report 'Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System' filed in response to a FERC directive.

**Lori Frisk - Allele - Minnesota Power, Inc. - 1**

**Answer**

Yes

**Document Name**

**Comment**

Minnesota Power supports the comments submitted by Edison Electric Institute (EEI) and the MRO NERC Standards Review Forum (NSRF).

Likes 0

Dislikes 0

**Response**

Thank you for your comment. See the responses for EEI and MRO NSRF.

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

**Answer**

Yes

**Document Name**

**Comment**

Ameren agrees with and supports EEI comments. In addition we would like more clarity around two items in this SAR:

- (1) the word "posting" used in Page 3, Project Scope, Item 3.
- (2) the phrase "all station elements" used in Page 4, Project Scope, Item 4. Does this include control houses, one or multiple?

Likes 0

Dislikes 0

**Response**

Thank you for your comment. See response to EEI.

Additionally, the team agrees with removing the word "posting". The team will also provide clarity on the details of what should be included within any simulation.

**Kent Feliks - AEP - 3,5,6**

**Answer**

Yes

**Document Name**

**Comment**

Kent Feliks on behalf of AEP in Segments 1, 3, 5, 6

We recommend removal of the statement, "To ensure that no instability occurs in simulation, registered entities can cover each broad type of stability analysis via Contingency analysis, governor power flow analysis, and transient stability analysis." The standard does not seek to ensure that "no instability occurs in simulation". It seeks to identify "widespread instability... within an Interconnection". Per FERC Order 802, only instability "critical to the operation of the Interconnection" is necessary to identify. The SDT must therefore qualify "instability" so that only critical instabilities are identified, for example, instability that results in such a loss of generation as to cause UFLS activation or that may lead to further cascading or to uncontrolled separation. Additionally, listing three methods of identifying instability as "via Contingency analysis, governor power flow analysis, and transient stability analysis" is contrary to other statements implying that dynamic simulations must be run to determine if there is instability. Contingency powerflow analysis and governor

powerflow analysis are not forms of dynamic simulation.	
Likes 0	
Dislikes 0	
<b>Response</b>	
The team agrees that the purpose of the CIP-014 standard is to identify impacts within an Interconnection. The term “widespread” will not be introduced, as it was removed from a previous version of the standard (see CIP-014-3 version history). Revisions to the SAR will be made to clarify the scope of instability being evaluated as well as language regarding types of studies.	
<b>Lindsey Mannion - ReliabilityFirst - 10</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you.	
<b>Cain Braveheart - Bonneville Power Administration - 1,3,5,6 - WECC</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Likes 0	
Dislikes 0	
<b>Response</b>	

Thank you.	
<b>Donna Wood - Tri-State G and T Association, Inc. - 1,3,5</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Likes	0
Dislikes	0
<b>Response</b>	
Thank you.	
<b>Joshua London - Eversource Energy - 1,3</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Likes	0
Dislikes	0
<b>Response</b>	
Thank you.	
<b>Dave Krueger - SERC Reliability Corporation - 10</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	

Likes	0
Dislikes	0
<b>Response</b>	
Thank you.	
<b>Alain Mukama - Hydro One Networks, Inc. - 1,3</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Likes	0
Dislikes	0
<b>Response</b>	
Thank you.	
<b>Steven Rueckert - Western Electricity Coordinating Council - 10, Group Name WECC CIP</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Likes	0
Dislikes	0
<b>Response</b>	
Thank you.	
<b>Israel Perez - Salt River Project - 1,3,5,6 - WECC</b>	
<b>Answer</b>	Yes



<b>Document Name</b>	
<b>Comment</b>	
Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you.	
<b>Gail Elliott - International Transmission Company Holdings Corporation - NA - Not Applicable - MRO,RF</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you.	
<b>Matt Lewis - Lower Colorado River Authority - 1,5</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Likes 0	
Dislikes 0	
<b>Response</b>	

Thank you.	
<b>Teresa Krabe - Lower Colorado River Authority - 1,5</b>	
<b>Answer</b>	Yes
<b>Document Name</b>	
<b>Comment</b>	
Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you.	

<b>2. Provide any additional comments for the SAR drafting team to consider, if desired.</b>	
<b>Kent Feliks - AEP - 3,5,6</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
<p><b>Regarding SAR Scope #5:</b> There are no recommended changes on the explicit language as written, however it is important for the drafting team to note that outages based on some of these recommended distance criteria would not be simultaneous. It is critical that the the outage scenarios required for study by the standard do not open the requirement up to studying nonsimultaneous outages of multiple stations, as this would create unbounded combined-outage analysis scenarios. In addition, loosely described distance criteria (line-of-sight, ease of access, etc.) may also create unreasonable unbounded analysis scenarios. Any such increase in risk assessment scope must be clearly and unambiguously defined within the standard.</p> <p><b>Regarding Cost Impact Assessments:</b> We strongly disagree with and recommend removal of the statement, “The cost impacts for the proposed changes to CIP-014-3 are expected to be minimal.”</p> <p>For small entities not currently performing analysis to determine local voltage angle instability, rotor angle instability, and frequency instability, given their small footprint's minimal impact on the stability of the Interconnection - these changes will require hiring/training new dynamic analysis expertise or outsourcing their CIP-014 risk assessment to consultants with this expertise. This will likely have a significant cost impact for these entities.</p> <p>For large entities performing these types of stability analyses on a subset of applicable stations whose loss pose a critical impact on the operation of the Interconnection, studying all stations for all types of local instability, even those that pose little to no risk to the operation of the Interconnection, will significantly increase the time to perform the risk assessment, and may also require staff augmentation or outside consultants to complete in a timely manner. This will also have a significant cost impact for these entities.</p>	
Likes	0
Dislikes	0
<b>Response</b>	

The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report 'Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System' filed in response to a FERC directive.

Revisions to the SAR will be made to clarify the scope of instability being evaluated as well as language regarding types of studies.

The team agrees that clarification on the cost impact statement in the SAR was needed. Language was revised in the SAR to clarify there may be cost impacts for revisions to the R1 risk assessment as well as potential downstream costs for additionally identified critical sites.

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

**Answer**

**Document Name**

**Comment**

None.

Likes 0

Dislikes 0

**Response**

Thank you.

**Kennedy Meier - Electric Reliability Council of Texas, Inc. - 2**

**Answer**

**Document Name**

**Comment**

ERCOT joins the comments submitted by the IRC SRC and adopts them as its own.

Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you for your comment. See the response to IRC SRC.	
<b>Marcus Bortman - APS - Arizona Public Service Co. - 1,3,5,6</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
AZPS does not have any additional comments for the SAR to consider at this time.	
Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you.	
<b>Bobbi Welch - Midcontinent ISO, Inc. - 2, Group Name ISO/RTO Council Standards Review Committee 2023-06 CIP-014 Risk Assessment SAR</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
The SRC notes that page 5 of the SAR lists Transmission Owners and Transmission Operators as the functional entities to which the standard should apply. The SRC agrees that these are the appropriate functional entities to which the standard should apply; however, the SRC also recommends that the standard drafting team include representatives from Planning Coordinators (PCs), Reliability Coordinators (RCs) and Transmission Planners (TPs), as these entities often perform verifications of risk assessments, and representatives from these functional entities will therefore be able to provide important perspectives to the drafting team even though the standard does not and should not apply to these functional entities. In the event the standard drafting team does not include representatives from	

one or more of these functional entities, the SRC recommend that the drafting team solicit feedback from these functional entities in the course of developing modifications to the standard.

Likes 0

Dislikes 0

**Response**

The team is comprised of members from various functions across the ERO. The team values diversity of opinions and will continue to consider comments from industry throughout the development process.

**Daniel Gacek - Exelon - 1,3**

**Answer**

**Document Name**

**Comment**

In the current Requirement 1, the 24-month study period in-service window limits the planners ability to consider projects that may mitigate the identified risk. The SAR drafting team should consider evaluating the 24-month study period in-service window and consider extending the window to 30-month. With a 30-month window, enties would be able to consider all substation elements expected to be placed into service, or retired, prior to the R1.1 30-month subsequent risk assessment required of entites that have identified one or more substations subject to the standard.

Likes 0

Dislikes 0

**Response**

The team will include this consideration when evaluating item 2 from the SAR.

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

**Answer**

**Document Name**

**Comment**

No additional comments.	
Likes	0
Dislikes	0
<b>Response</b>	
Thank you.	
<b>Dwanique Spiller - Berkshire Hathaway - NV Energy - 5</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
None at this time.	
Likes	0
Dislikes	0
<b>Response</b>	
Thank you.	
<b>Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Collaborators</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
Thank you for the opportunity to comment.	
Likes	0
Dislikes	0

Response	
Thank you.	
<b>Junji Yamaguchi - Hydro-Quebec (HQ) - 1,5</b>	
<b>Answer</b>	
<b>Document Name</b>	
Comment	
<p>The following changes from item number one of the Detailed Description should be made:</p> <p>Clarity should be added to the risk assessment to assure that instability is studied and that professional judgment assumptions are based on the investigation of instability.</p> <p>Including the word “fully” leads to increased difficulty in proving to an auditor that the stability studies being performed meet the expected threshold, the word should be removed. By saying “Clarity should be added to the risk assessment to assure that instability is studied,” there is still the expectation to study for instability without the added compliance pressure of being pseudo-zero-defect. As such, the revision should outline technical supporting expectations to clearly identify when an Applicable substation has demonstrated any form of instability. At a minimum, this revision should include specificity regarding the inclusion of transient dynamic studies to evaluate the conditions of the BPS.</p> <p>The word "not" should be removed. Entities should identify the Applicable substations that have demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.</p> <p>Entities should identify the Applicable substations that have demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.</p> <p>After reviewing the 5 criteria, the consistency between the risk-based approach established in CIP-002, the Facility is different than the proposed CIP-014 risk criteria. An example is relay clearance times to justify deeper physical security but CIP-002 may rate it as a low impact, but from a CIP-014 perspective it may require higher physical security controls that may not be commensurate with the risk assessed in CIP-002. This may include scenarios that end up requiring significant physical security controls, but not the equivalent level of cybersecurity-related controls; despite being the same station / Facility.</p>	



The proposed SAR is a parallel scoping criterion to CIP-002 based more on the function/impact of the system as opposed to rudimentary bright-line criteria. Please consider criteria 1-4 to be incorporated into another standard such as TPL-001, CIP-002, PRC, etc. Criteria 5 is security specific and could be incorporated in CIP-014.

Consider that if a physical evaluation requires the CIP-014 table 4.1.1.2 match the CIP-002 bright-line criteria. Recommending an objective-based input.

This assessment impacts not only changed scope but impacts downstream considerations which; therefore, will impact cost and may require long implementation timelines which address the risks identified in the risk assessment.

We strongly disagree with the Cost Impact Assessment of the SAR’s proposed methodology as being minimal. Conducting a large-scale stability study on a system of any reasonable size is very labor-intensive and can take anywhere from 3 to 6 months or more for a team of transmission planners.

Likes 0

Dislikes 0

**Response**

The team agrees with removal of the word “fully” from the SAR. The team will also revise the SAR to clarify specific requirement language regarding evaluating instability, uncontrolled separation, and Cascading within an Interconnection (by conducting steady-state and dynamic studies) while allowing for entity-specific flexibility in the development of study methods.

The team will consider what physical characteristics may be impactful to how the risk assessment is performed but any physical security controls resulting from critical station are considered out of scope for this project.

The team is not changing the scope to modify the applicability section criteria, including common criteria between CIP-002 and CIP-014. The team will include changes to the risk assessment and provide more clarity on others areas (such as physical proximity) to address the objectives of the SAR.

The team agrees that clarification on the cost impact statement in the SAR was needed. Language was revised in the SAR to clarify there may be cost impacts for revisions to the R1 risk assessment as well as potential downstream costs for additionally identified critical sites.

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

<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
None	
Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you.	
<b>Alain Mukama - Hydro One Networks, Inc. - 1,3</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
None	
Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you.	
<b>John Pearson - ISO New England, Inc. - 2</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
Regarding the cost impact assessment, the SAR states that cost impacts for the proposed changes to CIP-014-3 are expected to be	

minimal. The assessment appears to be based solely on modifications to system studies and does not seem to contemplate the additional spending that would be necessary on any stations newly identified as requiring physical security upgrades as a result of changes to the standard.

Likes 0

Dislikes 0

**Response**

The team agrees that clarification on the cost impact statement in the SAR was needed. Language was revised in the SAR to clarify there may be cost impacts for revisions to the R1 risk assessment as well as potential downstream costs for additionally identified critical sites.

**Brad Harris - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE**

**Answer**

**Document Name**

**Comment**

CEHE would like to take this opportunity to support and amplify the statement in the SAR Scope Detailed Description item #1: “This revision should not preclude entities from only conducting an evaluation for long-term studies (e.g., steady-state) or from only conducting dynamic simulations in some instances (e.g., not requiring additional study types once a site is already identified as critical).” CEHE does not want the R1 Risk Assessment requirements to limit flexibility.

Likes 0

Dislikes 0

**Response**

The team agrees with removal of the word “fully” from the SAR. The team will also revise the SAR to clarify specific requirement language regarding evaluating instability, uncontrolled separation, and Cascading within an Interconnection (by conducting steady-state and dynamic studies) while allowing for entity-specific flexibility in the development of study methods.

**Chantal Mazza - Hydro-Quebec (HQ) - 1 - NPCC**

**Answer**

**Document Name**

## Comment

The following changes from item number one of the Detailed Description should be made:

Clarity should be added to the risk assessment to assure that instability is studied and that professional judgment assumptions are based on the investigation of instability. Including the word “fully” leads to increased difficulty in proving to an auditor that the stability studies being performed meet the expected threshold, the word should be removed. By saying “Clarity should be added to the risk assessment to assure that instability is studied,” there is still the expectation to study for instability without the added compliance pressure of being pseudo-zero-defect.

As such, the revision should outline technical supporting expectations to clearly identify when an Applicable substation has demonstrated any form of instability. At a minimum, this revision should include specificity regarding the inclusion of transient dynamic studies to evaluate the conditions of the BPS.

The word "not" should be removed. Entities should identify the Applicable substations that have demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.

Entities should identify the Applicable substations that have demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.

After reviewing the 5 criteria, the consistency between the risk-based approach established in CIP-002, the Facility is different than the proposed CIP-014 risk criteria. An example is relay clearance times to justify deeper physical security but CIP-002 may rate it as a low impact, but from a CIP-014 perspective it may require higher physical security controls that may not be commensurate with the risk assessed in CIP-002. This may include scenarios that end up requiring significant physical security controls, but not the equivalent level of cybersecurity-related controls; despite being the same station / Facility.

he proposed SAR is a parallel scoping criterion to CIP-002 based more on the function/impact of the system as opposed to rudimentary bright-line criteria. Please consider criteria 1-4 to be incorporated into another standard such as TPL-001, CIP-002, PRC, etc.

Criteria 5 is security specific and could be incorporated in CIP-014.

Consider that if a physical evaluation requires the CIP-014 table 4.1.1.2 match the CIP-002 bright-line criteria.

Recommending an objective-based input.

This assessment impacts not only changed scope but impacts downstream considerations which; therefore, will impact cost and may require long implementation timelines which address the risks identified in the risk assessment.

We strongly disagree with the Cost Impact Assessment of the SAR’s proposed methodology as being minimal. Conducting a large-scale stability study on a system of any reasonable size is very labor-intensive and can take anywhere from 3 to 6 months or more for a team of transmission planners.

Likes 0

Dislikes 0

**Response**

The team agrees with removal of the word “fully” from the SAR. The team will also revise the SAR to clarify specific requirement language regarding evaluating instability, uncontrolled separation, and Cascading within an Interconnection (by conducting steady-state and dynamic studies) while allowing for entity-specific flexibility in the development of study methods.

The team will consider what physical characteristics may be impactful to how the risk assessment is performed but any physical security controls resulting from critical station are considered out of scope for this project.

Revisions were made to the SAR to clarify not needing to conduct additional risk assessment studies for a site once that site has been identified as critical.

The team is not changing the scope to modify the applicability section criteria, including common criteria between CIP-002 and CIP-014. The team will include changes to the risk assessment and provide more clarity on others areas (such as physical proximity) to address the objectives of the SAR.

The team agrees that clarification on the cost impact statement in the SAR was needed. Language was revised in the SAR to clarify there may be cost impacts for revisions to the R1 risk assessment as well as potential downstream costs for additionally identified critical sites.

**Michael Johnson - Pacific Gas and Electric Company - 1,3,5 - WECC, Group Name PG&E All Segments**

**Answer**

**Document Name**

Comment	
PG&E has no other input.	
Likes	0
Dislikes	0
Response	
Thank you.	
<b>Lucinda Bradshaw - Oncor Electric Delivery - 1 - Texas RE</b>	
Answer	
Document Name	
Comment	
No Comment	
Likes	0
Dislikes	0
Response	
Thank you.	
<b>Dave Krueger - SERC Reliability Corporation - 10</b>	
Answer	
Document Name	
Comment	
Under Project scope in #3, suggest adding "within each Interconnection is consistent" after the word Cascading.	
Under Detailed Description, suggest adding to #3 after the last sentence ending "application of a study method":	

For example, there should be a consistent method to establish the maximum amount of acceptable generation/load loss within each Interconnection. The methods might include coordination between PA/TP areas, RC areas, or with NERC Interconnection study groups. Entities should not have total flexibility when determining what does or does not affect the Interconnection.

Likes 0

Dislikes 0

**Response**

The phrase “within an Interconnection” was added in various parts of the SAR to be consistent with the current CIP-014 language.

The team agrees that adequacy and consistency for studies methods is within the scope of the SAR as written and will consider methods of assuring adequate consistency in study parameters and results, such as where multiple different Responsible Entities may own equipment in the same applicable Transmission substation or in multiple Transmission substations in close proximity.

**Jennie Wike - Tacoma Public Utilities (Tacoma, WA) - 1,3,4,5,6 - WECC, Group Name Tacoma Power**

**Answer**

**Document Name**

**Comment**

Tacoma Power recommends that if “line of sight” is used in the revised CIP-014 Standard, then it needs to be clearly defined. For example, substations located within 100 yards of each other.

Likes 0

Dislikes 0

**Response**

The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.

<b>April Ford - Southern Indiana Gas and Electric Co. - 3,5,6 - RF</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
<p>SIGE requests clarity around differing ownership for SAR Scope Detailed Description item #5: “The risk assessment should be revised to provide clear expectations regarding the inclusion of physically adjacent elements for the purpose of evaluating the impact from a physical attack.”</p>	
Likes 0	
Dislikes 0	
<b>Response</b>	
<p>The team acknowledges additional clarity is desirable in CIP-014 for entities dealing with physical proximity determinations as well as different ownership of applicable substations. The team will discuss and evaluate how to revise and clarify the risk assessment process to account for physical proximity considerations (line-of-sight, ease of access, etc.) to identify physically adjacent elements for the purpose of evaluating impact from a physical attack as well as different (incl. joint) ownership of identified adjacent Transmission stations/substations. The reviews will be performed in accordance with the SAR and the NERC Report ‘Evaluation of the Physical Security Reliability Standard and Physical Security Attacks to the Bulk-Power System’ filed in response to a FERC directive.</p>	
<b>Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name NPCC RSC</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
<p>The following changes from item number one of the Detailed Description should be made:</p> <p><b>Clarity should be added to the risk assessment to assure that instability is studied and that professional judgment assumptions are based on the investigation of instability.</b></p> <p>Including the word “fully” leads to increased difficulty in proving to an auditor that the stability studies being performed meet the</p>	



expected threshold, the word should be removed. By saying “Clarity should be added to the risk assessment to assure that instability is studied,” there is still the expectation to study for instability without the added compliance pressure of being pseudo-zero-defect.

**As such, the revision should outline technical supporting expectations to clearly identify when an Applicable substation has demonstrated any form of instability. At a minimum, this revision should include specificity regarding the inclusion of transient dynamic studies to evaluate the conditions of the BPS.**

The word "not" should be removed. Entities should identify the Applicable substations that *have* demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.

Entities should identify the Applicable substations that *have* demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.

After reviewing the 5 criteria, the consistency between the risk-based approach established in CIP-002, the Facility is different than the proposed CIP-014 risk criteria. An example is relay clearance times to justify deeper physical security but CIP-002 may rate it as a low impact, but from a CIP-014 perspective it may require higher physical security controls that may not be commensurate with the risk assessed in CIP-002. This may include scenarios that end up requiring significant physical security controls, but not the equivalent level of cybersecurity-related controls; despite being the same station / Facility.

The proposed SAR is a parallel scoping criterion to CIP-002 based more on the function/impact of the system as opposed to rudimentary bright-line criteria. Please consider criteria 1-4 to be incorporated into another standard such as TPL-001, CIP-002, PRC, etc.

Criteria 5 is security specific and could be incorporated in CIP-014.

Consider that if a physical evaluation requires the CIP-014 table 4.1.1.2 match the CIP-002 bright-line criteria.

Recommending an objective-based input.

This assessment impacts not only changed scope but impacts downstream considerations which; therefore, will impact cost and may require long implementation timelines which address the risks identified in the risk assessment.

We strongly disagree with the Cost Impact Assessment of the SAR’s proposed methodology as being minimal. Conducting a large-scale stability study on a system of any reasonable size is very labor-intensive and can take anywhere from 3 to 6 months or more for a team of

transmission planners.

Likes 0

Dislikes 0

**Response**

The team agrees with removal of the word “fully” from the SAR. The team will also revise the SAR to clarify specific requirement language regarding evaluating instability, uncontrolled separation, and Cascading within an Interconnection (by conducting steady-state and dynamic studies) while allowing for entity-specific flexibility in the development of study methods.

The team will consider what physical characteristics may be impactful to how the risk assessment is performed but any physical security controls resulting from critical station are considered out of scope for this project.

Revisions were made to the SAR to clarify not needing to conduct additional risk assessment studies for a site once that site has been identified as critical.

The team is not changing the scope to modify the applicability section criteria, including common criteria between CIP-002 and CIP-014. The team will include changes to the risk assessment and provide more clarity on others areas (such as physical proximity) to address the objectives of the SAR.

The team agrees that clarification on the cost impact statement in the SAR was needed. Language was revised in the SAR to clarify there may be cost impacts for revisions to the R1 risk assessment as well as potential downstream costs for additionally identified critical sites.

**Joshua London - Eversource Energy - 1,3**

**Answer**

**Document Name**

**Comment**

The following changes from item number one of the Detailed Description should be made:

**Clarity should be added to the risk assessment to assure that instability is studied and that professional judgment assumptions are**

**based on investigation of instability.**

Including the word “fully” leads to increased difficulty proving to an auditor that the stability studies being performed meet the expected threshold, the word should be removed. By saying “Clarity should be added to the risk assessment to assure that instability is studied,” there is still the expectation to study for instability without the added compliance pressure of being pseudo zero-defect.

**As such, the revision should outline technical supporting expectations to clearly identify when an Applicable substation has demonstrated any form of instability. At a minimum, this revision should include specificity regarding the inclusion of transient dynamic studies to evaluate conditions of the BPS.**

The word "not" should be removed. Entities should identify the Applicable substations that **have** demonstrated instability to ease the administrative burden by justifying the basis that any one substation has demonstrated instability through the studies performed versus proving that a station did not have instability.

Likes 0

Dislikes 0

**Response**

The team agrees with removal of the word “fully” from the SAR. The team will also revise the SAR to clarify specific requirement language regarding evaluating instability, uncontrolled separation, and Cascading within an Interconnection (by conducting steady-state and dynamic studies) while allowing for entity-specific flexibility in the development of study methods.

Revisions were made to the SAR to clarify not needing to conduct additional risk assessment studies for a site once that site has been identified as critical.

**Donna Wood - Tri-State G and T Association, Inc. - 1,3,5**

**Answer**

**Document Name**

**Comment**

NA

Likes 0

Dislikes 0	
<b>Response</b>	
Thank you.	
<b>Mark Garza - FirstEnergy - FirstEnergy Corporation - 1,3,4,5,6, Group Name FE Voter</b>	
<b>Answer</b>	
<b>Document Name</b>	
<b>Comment</b>	
See our response to Question 1.	
Likes 0	
Dislikes 0	
<b>Response</b>	
Thank you.	

**End of Report**