Comment Report

Project Name:	Project 2018-04 Modifications to PRC-024-2 | PRC-024-3 (Draft 1)
Comment Period Start Date:	4/17/2019
Comment Period End Date:	5/31/2019
Associated Ballots:	2018-04 Modifications to PRC-024-2 PRC-024-3 IN 1 ST

There were 69 sets of responses, including comments from approximately 169 different people from approximately 125 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The standards drafting team (SDT) replaced "protective relays" to "protection" throughout the standard to include relays, settings in applicable control systems, as well as other types of voltage and frequency protection devices. Do you agree with these modifications? If you do not agree, or if you agree but have comments or suggestions, provide your recommendation, explanation, and proposed modification

2. To address confusion regarding "at the point of interconnection," the team replaced it with the phrase, "at the high side of the generator step-up or collector transformer." Do you agree with this clarifying change? If not, please provide an alternative suggestion

3. The SDT modified Requirements R1 and R2 to not allow momentary cessation, in addition to tripping, in the "no trip zone." Do you agree that momentary cessation should not be allowed in the no trip zone? If not, please provide your rationale

4. Do you agree that "momentary cessation" – like "tripping" – is well understood by industry? If not, please provide your rationale

5. The SDT was apprised that, in some instances, the TO may own the GSU or collector transformers. As such, TOs were added to the applicable entity for cases where they may own a GSU or collector transformers with frequency and voltage protection enabled. Do you agree with the addition of TOs who own a GSU or collector transformer to the applicable entities? If not, please provide your rationale

6. Another intent of the facilities section was to clarify that voltage and frequency protection applied to plant auxiliary equipment is not applicable to the standard. Do you agree it is clear that plant aux equipment is out of scope of PRC-024? If not, please provide your rationale and a proposal

7. The SDT made several clarifying changes to the figures and tables (outlined in the SAR) to improve readability and eliminate confusion addressed in the SAR, including: (i) labeling the area outside the "No Trip Zone" as the "May Trip Zone;" (ii) removal of "ride-through" language; (iii) addition of "Minimum Time;" (iv) replacement of "instantaneous" with "0.10" seconds; and (v) clarifying modifications to the Voltage Boundary Clarifications. Do you agree with these modifications? If not, please recommend alternative solution(s)

8. The SDT added Quebec Interconnection-wide Variance to Requirement R2 with more stringent voltage boundaries for the No Trip Zone. Do you agree with this proposed Quebec Variance? If not, please provide your rationale

9. Do you agree with the proposed Implementation Plan? If not, please provide your rationale

10. Do you agree that the proposed modifications provide a cost-effective means of addressing issues in the SAR? If not, please provide an alternative, more cost-effective manner in which to achieve at least an equivalent level of reliability

11. If you have any additional comments on themes that have NOT already been addressed in the proceeding questions on this comment form, please provide them here

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Nick Batty	Keys Energy	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
Southwest Power Pool, Inc. (RTO)	Charles Yeung	2	SPP RE	SRC	Helen Lainis	IESO	2	NPCC
					Greg Campoli	NYISO	2	NPCC
					Lori Spence	MISO	2	MRO
					Mark Holman	PJM	2	RF
					Matt Goldberg	ISONE	1	NPCC
					Ali Miremadi	CAISO	1	WECC
					Nathan Bigbee	ERCOT	1	Texas RE
Santee Cooper	Chris Wagner	1		Santee Cooper	Deborah Schneider	Santee Cooper	1,3,5,6	SERC
					Bridget Coffman	Santee Cooper	1,3,5,6	SERC

					Wesley Brickle	Santee Cooper	1,3,5,6	SERC
					Paul Camilletti	Santee Cooper	1,3,5,6	SERC
MRO	Dana Klem	1,2,3,4,5,6	MRO	MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Powert	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service Corporation	3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent ISO	2	MRO
Douglas Webb	Douglas Webb		MRO,SPP RE	Westar-KCPL	Doug Webb	Westar	1,3,5,6	MRO
					Doug Webb	KCP&L	1,3,5,6	MRO
ACES Power Marketing	Jodirah Green	1,3,4,5,6	MRO,NA - Not Applicable,RF,SERC,Texas RE,WECC	ACES Standard Collaborations	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO

					Ginger Mercier	Prairie Power , Inc.	1,3	SERC
					Susan Sosbe	Wabash Valley Power Association	3	SERC
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3		DTE Energy - DTE Electric	Jeffrey Depriest	DTE Energy - DTE Electric	5	RF
					Daniel Herring	DTE Energy - DTE Electric	4	RF
					Karie Barczak	DTE Energy - DTE Electric	3	RF
Lincoln Electric System	Kayleigh Wilkerson	5		Lincoln Electric System	Kayleigh Wilkerson	Lincoln Electric System	5	MRO
					Eric Ruskamp	Lincoln Electric System	6	MRO
					Jason Fortik	Lincoln Electric System	3	MRO
					Danny Pudenz	Lincoln Electric System	1	MRO
Duke Energy	Kim Thomas	1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC
					Lee Schuster	Duke Energy	3	FRCC
					Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Katherine Prewitt	Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama Power Company	3	SERC

					William D. Shultz	Southern Company Generation	5	SERC
					Jennifer G. Sykes	Southern Company Generation and Energy Marketing	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and Con Ed	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Jones	National Grid	3	NPCC
					Sean Cavote	PSEG	4	NPCC
					Kathleen Goodman	ISO-NE	2	NPCC
					David Kiguel	Independent	NA - Not Applicable	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Gregory Campoli	New York Independent	2	NPCC

						System Operator		
					Caroline Dupuis	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					John Hastings	National Grid	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
Associated Electric Cooperative, Inc.	Todd Bennett	3		AECI	Michael Bax	Central Electric Power Cooperative (Missouri)	1	SERC
					Adam Weber	Central Electric Power	3	SERC

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

						Cooperative, Inc.		

1. The standards drafting team (SDT) replaced “protective relays” to “protection” throughout the standard to include relays, settings in applicable control systems, as well as other types of voltage and frequency protection devices. Do you agree with these modifications? If you do not agree, or if you agree but have comments or suggestions, provide your recommendation, explanation, and proposed modification

Matthew McMillan - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
We do not agree with replacing “protective relays” with “protection,” since it puts mechanical protection in-scope. NERC stated in their 4/30/2019 webinar that this is not the intent of the SDT, but there is no such restriction in PRC-024-3 as presently worded, and it in fact says the opposite. That is, there is a PRC-024-3 violation if a unit trips due to disturbance within the no-trip zone, regardless of reason – could be an under-frequency relay (correct), furnace main flame trip (incorrect), V/Hz relay (correct), motor control center contactor drop-out (incorrect), or any other reason. The original term should be retained. See also our response to question 11 below.	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No
Document Name	
Comment	
We do not agree with replacing "protective relays" with "protection," since it puts mechanical protection in-scope. NERC stated in their 4/30/2019 webinar that this is not the intent of the SDT, but their is no such restriction in PRC-024-3 as presently worded, and it in fact says the opposite. That is, there is a PRC-024-3 violation if a unit trips due to disturbance within the no-trip zone, regardless of reason - could be an under-frequency relay (correct), furnace main flame trip (incorrect), V/Hz relay (correct), motor control center contractor drop-out (incorrect), or any other reason. The original term should be retained. See also our response to question 11 below.	
Likes 0	
Dislikes 0	
Response	

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	

Comment	
Agree with EEI.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy recognizes the need to move away from the term “protective relay” used in the currently enforceable version of PRC-024; however, the use of the proposed term “protection” may be too broad to ensure that all applicable entities and industry stakeholders have a common understanding of what is included or required to ensure entity compliance with the proposed Reliability Standard PRC-024-3 Dominion Energy suggests the SDT either develop a proposed definition for the term “protection” or add additional language within the standard to provide context for the meaning of the term. When the SDT either defines the term or adds additional context within the standard, Dominion Energy recommends that the SDT does not create a conflict with the existing Protection System definition.	
Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
“**Protective relays” is an easily understood item and technical term. “Protection” can be interpreted more broadly and easily misconstrued. If the drafting team’s intention is to expand the applicability to include control systems on inverter based generation, then just add them to the scope and requirements and leave the protective relay terminology alone for non-inverter based generation**.	
Likes 0	
Dislikes 0	
Response	

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	
Comment	
LES recommends the following change to applicability section 4.2.1 to improve clarity: "Frequency, voltage or volts-per-hertz protection, including frequency or voltage protective functions within **inverter-based** control systems that provide tripping or momentary cessation signals…"	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The NSRF believe using the non-capitalized "protection" isn't sufficiently bounded. The drafting team needs to qualify protection with "protection systems that respond to electrical signals and directly trip the generating resource. Without these qualifications, the entire generating resource including auxiliary equipment is open to interpretation. If a variable frequency drive trips a boiler feed pump on a voltage transient that subsequently trips the plant itself, that should not be the intent. Many plants are large and complicated, so indirect trips should not be in scope. If the scope isn't contained, regulators after reviewing GADS reporting could ask if auxiliary systems were mapped to the high side GSU point of interconnection.	
Likes 0	
Dislikes 0	
Response	
Scott Berry - Scott Berry On Behalf of: Jack Alvey, Indiana Municipal Power Agency, 1, 4; - Scott Berry	
Answer	No
Document Name	
Comment	
In the attempt of the SDT to just add solar control systems to the standard, they may have also added control systems for non-solar generating units. For instance, gas turbines have turbine controls and exciter controls that may not consistently react to frequency and voltage excursions. For	

example, a combustion turbine governor system (fuel control) may try to chase the over and under event which may lead to combustion cans loosing flame and eventually a temperature differential trip. This type of event happen in southern Florida when the first version of PRC-024 happend and was reviewed by the SDT at that time. These control systems may trip off generating units in the “no trip” zone which would be a violation in the current draft of PRC-024-3. In most other conventional units, the exciter and turbine controls may be susceptible to tripping of the generator during voltage and frequency excursions. If these type of system controls are to be exempt, it is not clear in the draft that they are exempt. These type of systems should not be covered under the standard and if the standard wants to just add solar inverters to the standard that the SDT should use those exact words under the applicable Facilities section. The current wording under Facilities section 4.2.1 is too vague.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 1,3,5

Answer	No
Document Name	

Comment

NPPD suppports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

The standard’s language needs to be more generic. Various IBR control systems and protection systems design features (not just “protection”) have demonstrated the ability to cause curtailment of output for perturbations of frequency and voltage. The standard needs to require that none of these design features can cause IBR facilities to curtail output for frequency and voltage deviations within the limits specified in this standard.

Likes 0	
Dislikes 0	

Response

Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6

Answer	No

Document Name	
Comment	
Support the MRO NSRF Comments	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
SCANA- South Carolina Electric and Gas (Dominion Energy South Carolina) is in agreement with comments form Sean Bodkin (Dominion Energy).	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	
I agree with the comments submitted by Sean Bodkin-Dominion	
Likes 0	
Dislikes 0	
Response	
Scott Parker - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	

I am in agreement with comments submitted by Sean Bodkin-Dominion.

Likes 0	
Dislikes 0	

Response

Allen Schriver - NextEra Energy - 5

Answer	No
Document Name	

Comment

Comments: This is a Protective Relay Standard which does not include control systems. While the SAR states, "*Clarify if the voltage and frequency protective functions within an inverter control system that trip the inverter are subject to the requirements of PRC-024"*, it does not recommend inclusion of control systems. Control systems as designed by control engineers are to ensure required performance while operating within the equipment limits.

Also, based on events data to date, the inclusion of Volts/Hertz relaying on transformers has not been an issue and should not be written into the Standard.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

The text "settings in applicable control systems" needs to be revised to "generator frequency and voltage protection settings in applicable control systems" so that not all of the settings within the control system are in the scope.

Likes 0	
Dislikes 0	

Response

Thomas Savin - New York Power Authority - 6

Answer	No
Document Name	

Comment	
The scope of “protection” should be defined within the standard regarding protective relay settings and settings in applicable control systems. If “other” types of voltage and frequency protection devices need to be included, then we suggest explaining the scope.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Texas RE does not agree that using the term “protection” makes it clear that relays, settings in applicable control systems, as well as other types of voltage and frequency protection devices are included in the scope of the standard. Texas RE recommends using the term “protective function”.	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	

The term “protection” is very broad. The standard should include a footnote stating that “protection” is limited to devices which respond to electrical quantities and directly trip the generating resource.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

Comments: Kansas City Power & Light Company and Westar endorses comments submitted by EEI member companies.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

The NSRF believe using the non-capitalized “protection” isn’t sufficiently bounded. The drafting team needs to qualify protection with “protection systems that respond to electrical signals and directly trip the generating resource.

Without these qualifications, the entire generating resource including auxiliary equipment is open to interpretation. If a variable frequency drive trips a boiler feed pump on a voltage transient that subsequently trips the plant itself, that should not be the intent. Many plants are large and complicated, so indirect trips should not be in scope.

If the scope isn't contained, regulators after reviewing GADS reporting could ask if auxiliary systems were mapped to the high side GSU point of interconnection.	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
IPL agrees with the direction the SDT is going but recommends adding a definitions section such as "Section 6 Definitions Used in This Standard" in PRC-005, to clearly define "protection", "control systems", "momentary cessation", etc. in PRC-024-3.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed	
Answer	No
Document Name	
Comment	
The scope of "protection" should be defined within the standard regarding protective relay settings and settings in applicable control systems. If "other" types of voltage and frequency protection devices need to be included, then we suggest explaining the scope.	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	No
Document Name	
Comment	

AES agrees with the direction the SDT is going but recommends adding a definitions section such as “Section 6 Definitions Used in This Standard” in PRC-005, to clearly define “protection”, “control systems”, “momentary cessation”, etc. in PRC-024-3.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

EEI member companies recognize the need to move away from the term “protective relay” used in the currently enforceable version of PRC-024; however, the use of the proposed term “protection” may be too broad to ensure that all applicable entities have a common understanding of what is included or required to ensure entity compliance with the proposed Reliability Standard PRC-024-3. For example, entities may interpret the term to bring into scope mechanical protection issues and equipment that were not intended to be within the scope of this standard. For this reason, we suggest the SDT either develop a proposed definition for the term “protection” or add additional language within the standard to illustrate and clarify the term. To illustrate the type of definition that EEI member companies thinks is appropriate, we offer the following language for consideration:

Protection: Is a term used to describe a protective relay or functionally equivalent device (including multifunctional apparatus, computers or control systems) that provides the same functionality, as a traditional protective relay, when responding to various electrical quantities.

EEI member companies note that it has developed the above definition to ensure that it does not conflict with the existing Protection System definition and suggests that if the SDT decides to define protection, any similar potential for conflict should be avoided.

While EEI has not conducted an exhaustive assessment of where the term “protection” is used within the body of NERC Reliability Standards, we did find its use in the following Reliability Standards:

- Applicability section of most of the CIP Standards.
- FAC-010-3
- FAC-011-3
- PER-003-1
- PER-005-2 (Requirement R4 – protection system not capitalized)
- PRC-004-5(i)
- PRC-010-2
- PRC-015-1 (Within Purpose section – protection system not capitalized)
- PRC-017-1 (Within Purpose section – protection system not capitalized)
- PRC-019-2
- PRC-023-4
- PRC-024-2
- PRC-025-2
- TPL-001-4 (Table 1)

Likes 0	
Dislikes 0	

Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC	
Answer	No
Document Name	
Comment	
While we basically agree with changing protective relays to protection, we also seek clarification for requirement 4.2.1.5 "*Elements utilized in aggregation of the dispersed power producing resources"* of what could be an "elements" for applicability of the PRC-024 requirements. Dispersed power resources which operate in aggregate utilize a controller which has the capability to automatically trip the resources under certain high-side system frequency and voltage conditions. The settings for these controllers should also be considered as being applicable to the PRC-024 requirements regardless of their ownership.	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports RSC's comments.	
Likes 0	
Dislikes 0	

Response	
Bradley Collard - SunPower - 5	
Answer	No
Document Name	
Comment	
SunPower believes the term “protection” should be a defined in the Glossary of Terms or provide more detail as to what “protection” means in relation to the Standard. Distinguishing between voltage and frequency inverter control protection settings and other protection settings would help clarify this issue. The Standard should not bring in other types of control systems, only those that could trip generation as a direct result of voltage and/or frequency.	
Likes 0	
Dislikes 0	
Response	
Faz Kasraie - Seattle City Light - 5	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP does not disagree with the concept of replacing “protective relays” with “protection”, more detail and clarity is still needed regarding the scope of control systems.	
Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	

Comment
None

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	

Comment
AZPS is concerned that the term “protection” is unclear and could potentially expand the included devices and equipment beyond the intent of the Standards Drafting Team (SDT). To ensure clarity and consistency in the application of this term, the SDT could draft a definition or otherwise revise the standard to address the potential ambiguity that could result from use of the term “protection” alone. Further, without additional clarification or a definition, “protection” could be construed broadly by both registered entities and regional entities resulting in inconsistent application of the term and the associated requirements. The inclusion of devices and equipment that were never intended to protect the transmission system from the effects of a generator in obligations and activities intended to meet compliance with PRC-024-3 could be unduly burdensome without benefit to reliability. Finally, AZPS recommends that the SDT review the remaining reliability standards to review other uses of the term “protection” as it evaluates the potential clarifications and/or definitions that could address the ambiguity discussed above.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	

Comment
Exelon, Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
There should be a discussion as to what types of 'protection' that is known to be embedded in generator control systems. This will give those unfamiliar with how these embedded systems are typically setup (or known to be setup).	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
It seems the intention of NERC's Standard Authorization Request (SAR) and this change by the SDT is to clarify that protection functions within inverters are included within the scope of the Standard. However, based on the currently drafted language, this proposed change may also have the unintended effect of bringing other types of protections into the scope of this Standard. An example is the exciter protection of hydro generation units. This potential additional interpretation does not appear to be the intent of the SDT nor warranted. Specific exclusions of protections not intended to be brought into the Standard seems warranted, specifically exciter protection functions.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Chua - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shirley Mathew - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Darko Kovac, Gainesville Regional Utilities, 1, 5, 3; David Owens, Gainesville Regional Utilities, 1, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Nick Batty, Keys Energy Services, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio	
Answer	
Document Name	
Comment	
NCEMC supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	

2. To address confusion regarding “at the point of interconnection,” the team replaced it with the phrase, “at the high side of the generator step-up or collector transformer.” Do you agree with this clarifying change? If not, please provide an alternative suggestion

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC

Answer	No
Document Name	

Comment

Utilizing “at the high side of the generator step-up or collector transformer” may introduce a planning gap between the location of the generator step-up (GSU) or collector transformer and the true point of interconnection since Transmission Planners utilize the point of interconnection for planning purposes. Miles of transmission line may exist between a GSU or collector transformer and a point of interconnection. Specifying the high side of the GSU or collector transformer could introduce reliability issues and/or change system requirements due to the planning gap. One potential solution to be considered is utilizing “Point of Receipt,” which is defined in the NERC Glossary as “[a] location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.”

In addition, the SDT should consider the possibility that a GSU and collector transformer may both be present at a single generating Facility. [1]

[1] IESO and CAISO do not agree to this comment and are not considered as endorsing the SRC position for this response.

Likes 0	
Dislikes 0	

Response

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	No
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC supports the comments submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment
While EEI member companies support the substantive improvements made by the SDT through the replacement of the phrase “at the point of interconnection,” with the phrase, “at the high side of the generator step-up or collector transformer,” we continue to have some concerns that these changes may not be sufficiently bounded. For example, the currently proposed language in Section 4.2.1.5 has the potential of expanding the scope of Inclusion 4 since no limits are provided. Therefore, as an alternative suggestion, we ask the SDT to consider the following language for section 4.2.1.5, which we believe both limits the scope and better aligns with Inclusion 4 of the BES Definition: Elements designed primarily for the delivery of capacity from dispersed power producing resources. (or alternatively utilize the more simplified language provided in question 11)

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment
The NSRF does not agree with the addition of “collector transformer”, since we believe the SDT is referring to <100kV transformers (perhaps used in a collector system) which are out of scope per BES Definition I4. The SDT needs to quantify what transformers are within scope. The NSRF cannot support the use of the term “collector transformer”.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	

Comment
Comments: Kansas City Power & Light Company and Westar endorses comments submitted by EEI member companies.

Likes 0	

Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

An alternative is to use illustrations similar to those found in PRC-025-2 Table 1, page 37 & 38 to show exactly which facilities are being referred to.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

It is unclear if the generator step-up transformer is the inverter (the ac generator) step up transformer whose HV side is typically around 35kV, or it the generator step-up transformer is tne main station transformer whose HV side is typically from 115kV to 345kV. It is also unclear if the "collector transformer" is the same as the main station transformer described in the previous sentence. If the intention is that the point of analysis can be either of the two transformers discussed, then the replaced phrase in the draft version of the standard is fine.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	No
Document Name	

Comment

Exelon agrees that the Point of Interconnection may not always be the ideal location to apply the standard requirements, but it is however typically easy to identify. Sites may have multiple step-up or collector transformers. The proposed language while attempting to address confusion may create more uncertainty. As an alternative, Exelon suggests the team consider the following verbiage: “at the high side of the transformer that connects the aggregated generation resource to the transmission system.”

Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	
NPPD suppports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Scott Berry - Scott Berry On Behalf of: Jack Alvey, Indiana Municipal Power Agency, 1, 4; - Scott Berry	
Answer	No
Document Name	
Comment	

Some generating units have significant miles of line that connect its step-up transformer to their point of interconnection with their Transmission Owner. Therefore, the point of interconnection would not be the high side of the generator step up side. In FAC-008-3, Generator Owners have to use point of interconnection with its Transmission Owner in Requirement R2. This point should be the same for PRC-024.

Likes 0	
Dislikes 0	

Response

Alex Chua - Pacific Gas and Electric Company - 1,3,5

Answer	No
Document Name	

Comment

Flexibility should be allowed if the original studies were done at the point of interconnection: "at the point of interconnection or the high side of the generator step-up or collector transformer"

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

The NSRF does not agree with the addition of “collector transformer”, since we believe the SDT is referring to <100kV transformers (perhaps used in a collector system) which are out of scope per BES Definition I4. The SDT needs to quantify what transformers are within scope. The NSRF cannot support the use of the term “collector transformer”.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment
AZPS suggests generator side terminal voltage be used instead of the high-side voltage. Using high-side GSU voltage unnecessarily creates confusion and calculation burden, when there has been no realistic case study or other justification presented that would support using the terminal voltage or that indicates that use of the generator side terminal voltage will not be adequate. In fact, due to AVR, AZPS respectfully asserts that use of the generator terminal voltage is steadier and more appropriate than use of the high-side voltage.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5	
Answer	No
Document Name	

Comment
While AEP recognizes the SDT is attempting to provide clarification, it should be recognized that “Point of Interconnection” has been used within the standard since its implementation and also within interconnection service agreements. Making the suggested changes could lead to having multiple points of coordination within a facility, which would likely cause even more confusion. It is not always explicitly clear what the terms “generator step up” and “collector transformer” are referring to when referencing different sources of generation and projects involving multiple voltage step-ups or step-downs *prior* to the point of interconnection. We do not believe it is the drafting team’s intent to change what has historically been understood as the reference point of compliance for existing generation, and urge the SDT to not disrupt what has been recognized as the reference point of compliance.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	

Comment
OPG supports RSC’s comments.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed

Answer	Yes
Document Name	

Comment
The Standard Drafting team should clarify which Transformer a GO should consider when they have multiple Step Up or Collector transformers on line (multiple stages of step up to reach Interconnecting voltage)

Likes 0	
Dislikes 0	

Response

Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5

Answer	Yes
Document Name	

Comment
I am in agreement with comments submitted by Sean Bodkin-Dominion.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	Yes
Document Name	

Comment
Texas RE agrees this change provides clarity regarding previously incorrect usage of term “point of interconnection”.

Likes 0	
Dislikes 0	

Response

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Darko Kovac, Gainesville Regional Utilities, 1, 5, 3; David Owens, Gainesville Regional Utilities, 1, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Nick Batty, Keys Energy Services, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allen Schriver - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Parker - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shirley Mathew - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew McMillan - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio	
Answer	
Document Name	
Comment	
NCEMC supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	

Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	

3. The SDT modified Requirements R1 and R2 to not allow momentary cessation, in addition to tripping, in the “no trip zone.” Do you agree that momentary cessation should not be allowed in the no trip zone? If not, please provide your rationale

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

Agree with EEI

Likes 0	
Dislikes 0	

Response

Sergey Kynev - Siemens - Siemens Energy, Inc. - NA - Not Applicable - NA - Not Applicable

Answer	No
Document Name	

Comment

An exception for FACTS/HVDC devices has to be made. Shunt connected FACTS devices, like STATCOM or SVC do not have any energy source behind the power electronics and require to block (momentary cessation) during close-in fault (e.g. voltage below 0.3pu). This is a technology limitation, which is well understood and accepted in the industry.

This topic has been already addressed by NERC in Reliability Guideline BPS-Connected Inverter-Based Resource Performance App.E

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

While Dominion Energy generally supports the concept that resources intended to support BES reliability should not enter into “momentary cessation” within the “no trip zone”; the terms should be defined before using them within Reliability Standards. The meaning of “momentary cessation” may not

be consistently understood among all stakeholders and different organization have defined the term differently, as outlined in our response to question #4 below.	
Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	
Comment	
AZPS submits that the term “momentary cessation” is unclear based on differing definitions circulated in industry and that, as discussed above, ambiguity could create confusion and inconsistency in the application of the term both by registered entities and regional entities. For this reason, AZPS respectfully supports and reiterates EEI’s comments and recommendations regarding definition of “momentary cessation.”	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
This question is confusing as R1 and R2 do allow for tripping and or momentary cessation within the “no trip zone” with proper documentation. The NSRF believes the exception in R1 and R2 are needed for older equipment that cannot physically be changed to not trip, within the no trip zone.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	

NPPD suppports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF Comments	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
SCANA- South Carolina Electric and Gas (Dominion Energy South Carolina) is in agreement with comments form Sean Bodkin (Dominion Energy).	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	
I agree with the comments submitted by Sean Bodkin-Dominion	

Likes 0	
Dislikes 0	
Response	
Scott Parker - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Allen Schriver - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Comments: Inverters initiate momentary cessation due to voltages measured at their terminals. They initiate momentary cessation to protect the power electronics. The voltages seen at the terminals may be due to switching spikes on the low side of the GSU which may not be reflected in the voltage at the point of interconnection.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
In equipment where the implementation of momentary cessation is a control system response to systems conditions for which the controllability of the power conversion is not feasible, which is not a generator protective relay or generator protection system setting, making it out of the scope of the purpose of the standard. Therefore, references to "entering momemtary cessation" should not be part of this standard. Further, the first bullet under R1 and the fourth bullet of R2 in the current version of the standard *(…Generating unit(s) may trip if the protective functions (such as out-of-step functions*	

or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment….) should be retained rather than deleted because requiring a generating facility to not trip due to impending loss of synchronism, actual loss of synchronism, or due to instability in power conversion control equipment may exacerbate the system condition which originated the disturbance. That is, not allowing a unit to trip when it needs to trip in those instances can make the situation worse.

Likes 0	
Dislikes 0	

Response

Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5

Answer	No
Document Name	

Comment

I am in agreement with comments submitted by Sean Bodkin-Dominion.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment

This question is confusing because it does not address the exceptions in R1 and R2. Minnesota Power agrees that momentary cessation should not be allowed in the no trip zone, except where the standard allows for exceptions.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No

Document Name	
Comment	
Comments: Kansas City Power & Light Company and Westar endorses comments submitted by EEI member companies.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	
Comment	
This question is confusing as R1 and R2 do allow for tripping and or momentary cessation within the “no trip zone” with proper documentation. The NSRF believes the exception in R1 and R2 are needed for older equipment that cannot physically be changed to not trip, within the no trip zone.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI member companies generally agree that resources intended to support BES reliability should not enter into “momentary cessation” within the “no trip zone”; however, we believe that the industry must first define the term “momentary cessation” before applying it within Reliability Standards. For this reason, we cannot support its use at this time.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No

Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	No
Document Name	
Comment	
The question as asked is misleading. SunPower does not feel momentary cessation should be allowed except where it is infeasible to not allow due to equpment technical exceptions as allowed in R1 and R2.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	

Assuming this question is not contradicting the Requirement R2 exceptions.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon interprets momentary cessation as equivalent to a trip and automatic reclose, and agree momentary cessation should not be allowed in the no trip zone. Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	

However, momentary cessation should be defined in the standard, so that the term is clearly understood.

Likes 0	
Dislikes 0	

Response

Michael Goggin - Grid Strategies - 5 - NA - Not Applicable

Answer	Yes
Document Name	

Comment

I generally support the draft standard and believe its requirements are reasonable and achievable for newly installed inverters on a going-forward basis. However, I am concerned that the draft standard does not provide a workable means of compliance for the small share of the existing inverter fleet that cannot readily be updated to eliminate momentary cessation and meet the protection setting requirements in R1 and R2. NERC and others have determined that there is *de minimus* reliability risk from existing inverters that are unable to eliminate momentary cessation, so we strongly advise against imposing a costly retrofit or replacement requirement on those inverters that would not provide any measurable reliability benefit.

Specifically, footnote 5 in Requirement R3 on page 4 clarifies that the permissible exemption from the protection setting requirements in R1 and R2, due to a “known regulatory or equipment limitation,” “Excludes limitations that are caused by the setting capability of the generator frequency and voltage protection itself but does not exclude limitations originating in the equipment that it protects.” This footnote seems to deny the R3 equipment limitation exemption for inverters for which “the setting capability of the generator frequency and voltage protection itself” limits its ability to comply with R1 and R2. Our concern is that this would bar an existing inverter that cannot be updated to eliminate momentary cessation from using the R3 exemption. While we believe this requirement is reasonable for newly installed inverters on a going-forward basis, we do not believe it is a reasonable requirement for existing inverters that cannot be updated to eliminate momentary cessation, as it would likely require their replacement, or at least a costly retrofit.

Data collected through the NERC guideline indicates that of 13.5 GW of existing Bulk Power System solar resources that responded to the survey, only 1.8 GW were unable to fully mitigate the use of momentary cessation, while another 2.6 GW indicated that the use of momentary cessation can be mitigated through settings changes.

I propose that footnote 5 be modified to state “For projects that sign an interconnection agreement after the effective date of the standard, “known regulatory or equipment limitation” excludes limitations that are caused by the setting capability of the generator frequency and voltage protection itself but does not exclude limitations originating in the equipment that it protects. For inverters installed on or before that date, equipment limitations caused by the setting capability of the generator frequency and voltage protection itself is a permissible exemption under R3.” This will ensure that the Planning Coordinator and Transmission Planner is still notified of any equipment limitations, but will not require the costly retrofit of existing inverters than cannot meet the R1 and R2 requirements. We believe this strikes the appropriate balance between reliability concerns and cost.

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew McMillan - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Alex Chua - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shirley Mathew - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Darko Kovac, Gainesville Regional Utilities, 1, 5, 3; David Owens, Gainesville Regional Utilities, 1, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Nick Batty, Keys Energy Services, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)

Likes 0	
Dislikes 0	

Response

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio	
Answer	
Document Name	

Comment
NCEMC supports the comments submitted by ACES

Likes 0	
Dislikes 0	

Response

4. Do you agree that “momentary cessation” – like “tripping” – is well understood by industry? If not, please provide your rationale

Bradley Collard - SunPower - 5	
Answer	No
Document Name	
Comment	
SunPower believes NERC would do well by defining the term, “momentary cessation” as either part of this Standard or in the Glossary of Terms. As others have pointed out, this term relates primarily to PV Inverters. Is there a difference between “stop injecting current” and “momentary cessation?” Inverters tripping due to voltage or frequency is a function that protects the inverter and takes longer to recover. Momentary cessation may be a very temporary issue.	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	
OPG supports RSC’s comments.	
Likes 0	
Dislikes 0	
Response	

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	

Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

While there is a better understanding of momentary cessation since the Blue Cut and Canyon 2 fires, EEI member companies do not agree that this term is sufficiently and consistently understood by industry. The SDT should define the term in the NERC Glossary of Terms to ensure consistency in application.

To assist in this effort, we note that the Inverter-Based Resource Performance Task Force (IRPTF) provided a definition for "momentary cessation" within their assessment titled "Resource Loss Protection Criteria Assessment NERC Inverter-Based Resource Performance Task Force (IRPTF) White Paper – February 2018" (see below):

Momentary cessation is defined as an inverter operating mode where the inverter temporarily ceases injection of active and reactive current ("zero current injection") into the point of connection with the grid. The power electronic firing commands are blocked, and therefore the inverter does not exchange any current (real or reactive) with the grid. Other operating modes where active or reactive power are prioritized based on inverter controls are not considered momentary cessation since the power electronic switches are still firing and current is being exchanged with the grid.

Additionally, we note that within IEEE Standard 1547 "momentary cessation" is also defined as:

momentary cessation: Temporarily cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate Restore Output of operation when the applicable voltages and the system frequency return to within defined ranges.

Other Related definitions within IEEE 1547 include:

cease to energize: Cessation of active power delivery under steady-state and transient conditions and limitation of reactive power exchange.

applicable voltage: Electrical quantities that determine the performance of a Local EPS or DER specified with regard to the reference point of applicability, individual phase-to-neutral, phase-to-ground, or phase to-phase combination and time resolution.

restore output: Return operation of the DER to the state prior to the abnormal excursion of voltage or frequency that resulted in a ride-through operation of the DER.

reference point of applicability (RPA): The location where the interconnection and interoperability performance requirements specified in this standard apply

Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	No

Document Name	
Comment	
A definition of momentary cessation as it applies to PRC-024-3 should be included in the suggested “Definitions” section of the new Standard as stated in AES' response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed	
Answer	No
Document Name	
Comment	
We suggest that the term “momentary cessation” be defined within the standard to avoid misunderstanding.	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	No
Document Name	
Comment	
A definition of momentary cessation as it applies to PRC-024-3 should be included in the suggested “Definitions” section of the new Standard as stated in IPL’s response to Question 1.	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	No
Document Name	

Comment
Comments: Currently, the NSRF can only refer to the February 2018 Modeling Notification: Recommended Practices of Modeling Momentary Cessation. Where Momentary cessation is an inverter operating state where the power electronic “firing commands” are blocked such that both active current and reactive current go to zero output. Since this is not defined by NERC, we do not know if a Compliance Enforcement Agency would use a different definition for Momentary Cessation. Please consider a definition for Momentary Cessation.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment
Comments: Kansas City Power & Light Company and Westar endorses comments submitted by EEI member companies.

Likes 0	
Dislikes 0	

Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1

Answer	No
Document Name	

Comment
Even if the term is thought to be well understood, it should be clearly defined either in this standard or in the NERC Glossary of Terms.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
This topic is somewhat new to the industry and the growth of the renewable energy requires additional focus and elaboration on this topic by NERC.	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6	
Answer	No
Document Name	
Comment	
Momentary cessation is not well understood by Entities with no inverter-based generation resources. It would benefit industry if the term was defined or discussed in PRC-024-3, Compliance Guidance, or the Glossary of Terms Used in NERC Reliability Standards.	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	No
Document Name	
Comment	
Texas RE recommends the SDT consider defining the term momentary cessation. While momentary cessation is a familiar term for PV power plants, wind and other renewable generation resources have different terminology for ceasing power injection. If the term is defined, there is a greater chance it will be consistently applied.	
Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority - 6	
Answer	No
Document Name	
Comment	
We suggest that the term “momentary cessation” be defined within the NERC Glossary of Terms or the standard to avoid misunderstanding.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
This topic is somewhat new to the industry and the growth of the renewable energy requires additional focus and elaboration on this topic by NERC.	
Likes 1	Associated Electric Cooperative, Inc., 1, Ziegler Ryan
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No

Document Name	
Comment	
Many in the industry incorrectly equate momentary cessation with tripping. Momentary cessation is quite different from tripping. It is a control action rather than a protection system action. Protective relaying systems and schemes trip generating facilities using auxiliary/lockout relays and power circuit breakers, and require manual intervention so that investigation, analysis, reset, and restorative actions may be taken. The action taken by momentary cessation functions, whereby an automatic restoration/return to pre-disturbance conditions is executed, is similar to, and much closer in comparison to, a control system limiter rather than a generator protection system whose action is to trip. The temporary limitations or temporary changes to the mode-of-control performed by the momentary cessation portion of the control system does not trip the unit in the traditional protection system fashion of operation. Including this control sytem action does not fit the title and purpose of this standard. The inclusion of this control system action requirement transforms this standard into a entire facility ride-thru performance standard. The addition of "continuing to support the BES" as a change in the purpose statement furthers this effort to change the standard from a protection setting standard to a plant performance standard. The original draft versions of PRC-024-1 attempted to establish a plant performance ride-thru standard, and the overwhelming negative industry vote for that version of the standard clearly demonstrated the objection to this type of standard.	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	No
Document Name	
Comment	
Momentary cessation is a relatively new term , especially to those that do not currently have inverter based generation.	
Likes 0	
Dislikes 0	
Response	
Allen Schriver - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Comments: Tripping is associated with a mechanical action and the facility typically goes “off-line”. Momentary cessation is only associated with the operation of inverter technology. Technically, when the inverter goes into momentary cessation, it may, or may not, “trip” the facility; thus, it may, or may not, go “off-line”.	
Likes 0	

Dislikes 0	
Response	
Scott Parker - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Shirley Mathew - Austin Energy - 5	
Answer	No
Document Name	
Comment	
“Tripping” is associated with opening of an electric circuit via an interrupting device and separating the electrical equipment from the grid. The opening of the circuit will not conduct electricity until the interrupting device is closed back to regain the continuous loop circuit. Tripping of an interrupting device has inherent time delay which includes detection time, computation time, tripping signal transmit time and interrupting device opening time. “Momentary cessation” is an inverter ‘open state’ of an electronic component. There is no interrupting device disconnecting the electrical equipment. However, the industry considers “momentary cessation” in the same meaning as “’tripping”. Momentary cessation = Active current is not produced Tripping = Active current is interrupted	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	

“Tripping” is associated with opening of an electric circuit via an interrupting device and separating the electrical equipment from the grid. The opening of the circuit will not conduct electricity until the interrupting device is closed back to regain the continuous loop circuit. Tripping of an interrupting device has inherent time delay which includes detection time, computation time, tripping signal transmit time and interrupting device opening time.

“Momentary cessation” is an inverter ‘open state’ of an electronic component. There’s no interrupting device disconnecting the electrical equipment. However, the industry considers “momentary cessation” in the same meaning as “’tripping”.

Momentary cessation = Active current is not produced

Tripping = Active current is interrupted

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

This term is not as well-known as “tripping” to those in the industry who are strictly compliance professsionals. Explanation is warranted.

Likes 0	
Dislikes 0	

Response

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1

Answer	No
Document Name	

Comment

I agree with the comments submitted by Sean Bodkin-Dominion

Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	No
Document Name	
Comment	
SCANA- South Carolina Electric and Gas (Dominion Energy South Carolina) is in agreement with comments form Sean Bodkin (Dominion Energy).	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Duke Energy believes that issues at IBR facilities such as momentary cessation and tripping due to PLL error, as well as other protection and controls systems design features that can cause facility curtailment, are not well understood by industry. The language of the standard needs to be generic enough to cover any of these design features that can cause facility curtailment for any reason under frequency and voltage disturbances.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No

Document Name	
Comment	
NPPD suppports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Scott Berry - Scott Berry On Behalf of: Jack Alvey, Indiana Municipal Power Agency, 1, 4; - Scott Berry	
Answer	No
Document Name	
Comment	
Momentary cessation is a vague term and can have different meanings in the industry. If the standard keeps this term, it should be defined to eliminate the vagueness of the term.	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	No
Document Name	
Comment	
It would be helpful to define this term, though its meaning can be deduced by it’s context and the definition of cessation.	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	

Currently, the NSRF can only refer to the February 2018 Modeling Notification: Recommended Practices of Modeling Momentary Cessation. Where Momentary cessation is an inverter operating state where the power electronic “firing commands” are blocked such that both active current and reactive current go to zero output. Since this is not defined by NERC, we do not know if a Compliance Enforcement Agency would use a different definition for Momentary Cessation. Please consider a definition for Momentary Cessation.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	No
Document Name	

Comment

As discussed above, many different definitions of “momentary cessation” are being advanced in industry. While AZPS subject matter experts have a good understanding of what momentary cessation means to them, the potential for various and varied meanings and applications could reduce the value and benefit of this standard to reliability and create complications and unintended consequences during real-time operations.

Likes 0	
Dislikes 0	

Response

Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5

Answer	No
Document Name	

Comment

Not everyone in the industry deals with DC power and inverters

Likes 0	
Dislikes 0	

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer	No
Document Name	

Comment
The term, “momentary cessation,” may not be well understood by entities that do not own inverter-based resources, and should be explained in PRC-024-3

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	

Comment
Momentary cessation is used with inverter based resources (solar panels). Those resources are not in everyone’s fleet and may not have been studied by protection engineers. Concerns arise as to why there is momentary cessation, exactly when it is triggered, when does it resume, and can those trigger points be changed?

Likes 0	
Dislikes 0	

Response

Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	No
Document Name	

Comment
Although the term may be well understood by owners of inverter-based facilities, including time parameters may provide additional clarity for those that do not currently own or operate these types of facilities as well as improve consistency in future enforcement activities.

Likes 0	
Dislikes 0	

Response

Sergey Kynev - Siemens - Siemens Energy, Inc. - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	

Comment
“Momentary cessation”, as it is defined in other NERC documents, refers to as "blocking" of inverter. Blocking is well understood term among manufactures of inverters. However, it seems that "momentary cessation" also covers the period after blocking, then current output is recovering to its pre-fault value. Therefore, it is not clear if any limitation of inverter current output is referred as "momentary cessation" or only the one, that involve blocking. For instance, if an inverter reduces its current output to 10% (could be any value) of its original value during a fault, but does not block, would it be considered a "momentary cessation"?

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	

Comment
agree with EEI.

Likes 0	
Dislikes 0	

Response

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	No
Document Name	

Comment
The concept of “momentary cessation” may be well understood, however it is doubtful that the behavior of existing installed power producing resources is understood. Typical power producing resource documentation does not include the terminology “momentary cessation”.

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	No

Document Name	
Comment	
The Term, "momentary cessation," may not be well understood by entities that do not own inverter-based resources, and should be explained in PRC-024-3.	
Likes 0	
Dislikes 0	
Response	
Matthew McMillan - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
The term, “momentary cessation,” may not be well understood by entities that do not own inverter-based resources, and should be explained in PRC-024-3.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
The meaning of Momentary Cessation is becoming more know in the industry. The term as utilized in the Standard should be formally defined in the NERC Glossary of Terms. Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	

Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
In Ontario, momentary cessation – like tripping is well understood.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Darko Kovac, Gainesville Regional Utilities, 1, 5, 3; David Owens, Gainesville Regional Utilities, 1, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Nick Batty, Keys Energy Services, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Alex Chua - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio	
Answer	
Document Name	

Comment	
NCEMC supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	
Document Name	
Comment	

While there is a better understanding of momentary cessation since the Blue Cut and Canyon 2 fires, Dominion Energy does not agree that this term is sufficiently and consistently understood by all stakeholders. The SDT should define the term in the NERC Glossary of Terms to ensure consistency in understanding.

To assist in this effort, Dominion Energy has identified that the Inverter-Based Resource Performance Task Force (IRPTF) provided a definition for "momentary cessation" within their assessment titled "Resource Loss Protection Criteria Assessment NERC Inverter-Based Resource Performance Task Force (IRPTF) White Paper – February 2018" (see below):

Momentary cessation is defined as an inverter operating mode where the inverter temporarily ceases injection of active and reactive current ("zero current injection") into the point of connection with the grid. The power electronic firing commands are blocked, and therefore the inverter does not exchange any current (real or reactive) with the grid. Other operating modes where active or reactive power are prioritized based on inverter controls are not considered momentary cessation since the power electronic switches are still firing and current is being exchanged with the grid.

Additionally, we note that within IEEE Standard 1547 "momentary cessation" is also defined as:

momentary cessation: Temporarily cease to energize an EPS, while connected to the Area EPS, in response to a disturbance of the applicable voltages or the system frequency, with the capability of immediate Restore Output of operation when the applicable voltages and the system frequency return to within defined ranges.

Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	

Response

5. The SDT was apprised that, in some instances, the TO may own the GSU or collector transformers. As such, TOs were added to the applicable entity for cases where they may own a GSU or collector transformers with frequency and voltage protection enabled. Do you agree with the addition of TOs who own a GSU or collector transformer to the applicable entities? If not, please provide your rationale

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

agree with EEI.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Dominion Energy does not agree that TOs should be added to the Applicability section of PRC-024-3. PRC-024 is a Reliability Standard that was developed to ensure that protective relay settings were developed and set in a manner that ensure that generating resources remain connected to the BES during defined frequency and voltage excursions. Mere ownership of GSUs or collector transformers does not represent an integral part of the affected relay protection beyond some possible shared devices (i.e., voltage and current sensing devices) providing input to affected protection functions. Dominion Energy is not aware of any TOs that own generator protective relays unless they are also registered as a GO in which case they would be obligated under PRC-024 to comply with the Reliability Standard requirements for these devices as a GO. In addition, such devices are not protection devices and therefore do not warrant making owners of these Facilities applicable entities under this Reliability Standard. Dominion Energy is also unaware of any reliability incident where a BES generating resource failed to perform within the requirements of PRC-024 as a result of a TO owning a GSU or collector transformer, so we are unaware of any reliability risk that might merit such a change.

Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment
The scope of the standard is for generator protection. How does that include transformer protection?

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	No
Document Name	

Comment
While AZPS understands why the TO and aforementioned equipment was added to this proposed revision of PRC-024, AZPS respectfully submits that this equipment is not intended for the protection of the generators and that, to include them in this standard, results in an inappropriate shift of compliance and cost responsibility from the GO to the TO. Further, the TO already has responsibility for relay and other protections associated with its operation of its transmission system. If additional responsibilities were to be added, revisions associated therewith should, for consistency reasons, be applied within the existing standards associated with these obligations. For these reasons, AZPS submits that the SDT should not include TOs or their equipment relative to PRC-024.

Likes 0	
Dislikes 0	

Response

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	

Comment
I agree with the comments submitted by Sean Bodkin-Dominion

Likes 0	
Dislikes 0	

Response

Scott Parker - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No

Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Allen Schriver - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Comments: Transmission Owners (TOs) that own asynchronous ties must also be included. Transmission asynchronous interties exhibit the same momentary cessation issues due to voltage and frequency excursions as solar inverters, (see the Pacific DC Intertie information in the WECC May 11, 2018 event report). Any revisions to the Standard should include asynchronous interties in order to properly address the concerns associated with all inverter operations.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
This standard was originally written for generator protective relaying. The proposed scope change make it written for generator protection. Relaying owned by the TO for transformer protection is not in the scope of this standard. The TO does not have protection elements on the GO's generator.	
Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority - 6	
Answer	No

Document Name	
Comment	
The focus of the standard should be on the Generator Owner's protective devices. It is not necessary to add Transmission Owners to the applicability of the standard simply because some Transmission Owners may own Elements that are being tripped by the Generator Owner's protective devices.	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	No
Document Name	
Comment	
Comments: Kansas City Power & Light Company and Westar endorses comments submitted by EEI member companies.	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed	

Answer	No
Document Name	
Comment	
The focus of the standard should be on the Generator Owner's protective devices. We believe that it is not necessary to add Transmission Owners to the applicability of the standard simply because some Transmission Owners may own Elements that are being tripped by the Generator Owner's protective devices.	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI member companies do not agree that TOs should be added to the Applicability section of PRC-024-3. PRC-024 is a Reliability Standard that was developed to ensure that protective relay settings were developed and set in a manner that ensure that generating resources remain connected to the BES during defined frequency and voltage excursions. EEI member companies are also not aware of any TOs that own generator protective relays unless they are also registered as a GO in which case they would be obligated under PRC-024 to comply with the Reliability Standard requirements for these devices as a GO. For these reasons, EEI member companies do not support the proposed changes in applicability which we believe create new compliance requirements that do not provide any known benefits to reliability.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
While AEP does not object to the TO as specified being brought into applicability, there may be instances where the GSU or collector transformer is owned by one Registered Entity while the protection (as specified in Section 4.2.1) is owned by a different Registered Entity. As currently drafted, the transformer assets in this scenario would not technically be within the scope of the standard.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	

Answer	Yes
Document Name	
Comment	
Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew McMillan - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Alex Chua - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Shirley Mathew - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Darko Kovac, Gainesville Regional Utilities, 1, 5, 3; David Owens, Gainesville Regional Utilities, 1, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Nick Batty, Keys Energy Services, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	

Comment	
The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio	
Answer	
Document Name	
Comment	
NCEMC supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	

6. Another intent of the facilities section was to clarify that voltage and frequency protection applied to plant auxiliary equipment is not applicable to the standard. Do you agree it is clear that plant aux equipment is out of scope of PRC-024? If not, please provide your rationale and a proposal

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports RSC's comments.

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC

Answer	No
Document Name	

Comment

In general, we do not agree with excluding plant auxiliary equipment from the scope of the standard. Auxiliaries critical to maintain plant output must also be considered. For example, loss of primary heat transport supply to primary heat pumps in a CANDU[1]nuclear design or fuel gas compressors in a gas plant will result in reduced plant output. The supply to other critical auxiliaries like lubricating systems, governing and excitation systems that allow the generating unit to maintain its output level also must meet PRC-024 requirements for reliability. Recognizing the difficulty in determining when auxiliary equipment will trip, it may be appropriate to provide an extended phased in implementation period to determine auxiliary equipment based trip points.[i]

[1] Canada Deuterium Uranium, is a Canadian pressurized heavy-water reactor design used to generate electric power. The acronym refers to its deuterium oxide (heavy water) moderator and its use of (originally, natural) uranium fuel.

[i] ERCOT and CAISO do not agree with this recommendation and do not support this SRC response.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment
EEI member appreciate the efforts made by the SDT to address EEI member company concerns related to the exemption of auxiliary equipment but do not believe the language is clear. For this reason, we have provided alternative language within the Applicability section of PRC-024-3 in our response to Question 11 for SDT consideration.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed

Answer	No
Document Name	

Comment
Having auxiliaries trip too early on voltage or frequency which cause output to change is by definition an interaction between the plant and the power system. If the tripping auxiliaries do not affect P,Q, or Vt of the units at the plant, then they do not need to be considered. We suggest an explicit statement be added to the Applicability section of the standard that auxiliary equipment is not applicable to the standard. We also suggest that auxiliary equipment be defined within the standard or examples of auxiliary equipment be provided within the standard.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment
Comments: 4.2.1.3 states, High side of the generator-connected **unit auxiliary transformer** installed on BES generating resource(s). Does this mean the aux transformer will be in scope if it is connect up stream of the high side terminals of the generator's GSU? If so, then 4.2.1.3 should read: *Aux transformers that are connected between the high side terminals of the generator's GSU and the BES Interconnection*. The MRO NSRF suggests the SDT consider adding wording and pictures (such as PRC-025 figures 5,7, and 8) that better define aux transformers for consistency. The SDT could state something like the following in the Facilities section:

Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online. These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running.

Pictures

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

Comments: Kansas City Power & Light Company and Westar endorses comments submitted by EEI member companies.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	No
Document Name	

Comment

We believe additional clarification is required. This could be met by adding a footnote or clear language stating that the plant auxiliary equipment is out of scope of PRC-024.

Likes 0	
Dislikes 0	

Response

Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5

Answer	No
Document Name	

Comment

I am in agreement with comments submitted by Sean Bodkin-Dominion.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	No
Document Name	

Comment

Texas RE inquires: where it says “all or part of the generating resource” in section 4.2.1, does a derate of a synchronous resource now fall within the applicability of the standard?

Texas RE is concerned Section 4.2 is not clear that voltage and frequency protection applied to plant auxiliary equipment is not applicable to the standard. While auxiliary transformers are not mentioned elsewhere in the standard, section 4.2.1.3 states “high side of the generator connected unit auxiliary transformer installed on BES generation resource(s).” Since this mentions auxiliary transformers, it could lead to confusion.

Additionally, Texas RE is concerned that frequency, voltage or volts per hertz protection identified under “Facilities” in section 4.2.1 is not consistent with the NERC Glossary definition of Facilities which refers to “a set of electrical equipment that operates as a single Bulk Electric System Element”. This could cause confusion with use of the term Facilities throughout the standards and implementation plans.

Furthermore, the wording “within control systems” in section 4.2.1 should be clarified because the term is very broad. For synchronous generators, is the control system limited to the plant DCS, or does it also include the excitation controls, AVR, and boiler control systems? Each of these control

systems may have frequency or voltage protective functions that could trip or derate the generator. This phrase could also unintentionally include balance of plant equipment such as forced draft fans, feed pumps, air compressors, and other equipment that was probably not intended by the SDT.

Likes 0	
Dislikes 0	

Response

Thomas Savin - New York Power Authority - 6

Answer	No
Document Name	

Comment

Having auxiliaries trip too early on voltage or frequency which cause output to change is by definition an interaction between the plant and the power system. If the tripping auxiliaries do not affect P,Q, or Vt of the units at the plant, then they do not need to be considered. We suggest an explicit statement be added to the Applicability section of the standard that auxiliary equipment is not applicable to the standard. We also suggest that auxiliary equipment be defined within the standard or examples of auxiliary equipment be provided within the standard.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We believe additional clarification is required. This could be met by adding a footnote or clear language stating that the plant auxiliary equipment is out of scope of PRC-024.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

As written, the facilities section includes much more than the generator protection or generator protective relays. The phrase "all or part of the generating resource" includes all eqiupment. To make it clear that the applicability does not include the plant auxiliary equipment, Section 4.2 should be rewritten as follows….. *4.2.1 Frequency, voltage or volts per hertz protection, including frequency or voltage protective functions within Individual dispersed power producing resources identified in the BES Definition, Inclusion I4.* The expansion of the Facilities section included in this draft of version 3 of the standard is unnecessary. Generator owners required to register as GO's already are aware of the included equipment based on the BES definition. Facilities section 4.2.1.5 expands the scope of the BES definintion and should not be included. We also contend that protection systems do not initiate momentary cessation. The control system determination that a condition where "lack of control" ability is what initiates momentary cessation, a strictly control function, not a protective function. In section 4.2.1, "or momentary cessation" should be removed.

Likes 0	
Dislikes 0	

Response

Scott Parker - SCANA - South Carolina Electric and Gas Co. - 3

Answer	No
Document Name	

Comment

I am in agreement with comments submitted by Sean Bodkin-Dominion.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Reclamation recommends the SDT strive to draft the clearest possible standards. It would be more clear that plant aux equipment is out of scope of PRC-024 if it was specifically stated as being excluded.

Likes 0	
Dislikes 0	

Response

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1

Answer	No
Document Name	
Comment	
I agree with the comments submitted by Sean Bodkin-Dominion	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	
NPPD suppports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Scott Berry - Scott Berry On Behalf of: Jack Alvey, Indiana Municipal Power Agency, 1, 4; - Scott Berry	
Answer	No
Document Name	

Comment
If plant auxiliary equipment is not applicable to the standard, it should be clearly stated in the standard instead of saying it is not applicable because it is not listed under Facilities. However, it might not be clear what is all included in the category of auxiliary equipment. What one plant views equipment to be auxiliary may not be the same for other generating plants. By making an attempt to only include certain equipment and by not stating the status of specific other equipment (i.e. auxiliary equipment) it may not be clear to an entity or an auditor if the other equipment is included, especially when the included equipment terms are vague and might be more encompassing than intended by the SDT. In addition, during a frequency or voltage event, auxiliary equipment will likely trip offline and cause the generation to trip offline. If this happens in the no trip zone, the standard does not address if this would be allowed or not.

Likes 0	
Dislikes 0	

Response

Alex Chua - Pacific Gas and Electric Company - 1,3,5	
Answer	No
Document Name	

Comment
It is not. Examples of equipment in scope should be detailed in a few examples such as those found in the application guideline for PRC-025-2

Likes 0	
Dislikes 0	

Response

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	Project 2018-04 PRC-024-3 NSRFl Comment Form 05-29-2019.docx

Comment
4.2.1.3 states, High side of the generator-connected **unit auxiliary transformer** installed on BES generating resource(s). Does this mean the aux transformer will be in scope if it is connect up stream of the high side terminals of the generator's GSU? If so, then 4.2.1.3 should read: *Aux transformers that are connected between the high side terminals of the generator's GSU and the BES Interconnection*. The MRO NSRF suggests the SDT consider adding wording and pictures (such as PRC-025 figures 5,7, and 8) that better define aux transformers for consistency. The SDT could state something like the following in the Facilities section:

Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online. These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running.

See illustrations in attachment.

Likes 0	
Dislikes 0	

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer	No
Document Name	

Comment

We believe additional clarification is required. This could be met by adding a footnote or clear language stating that the plant auxiliary equipment is out of scope of PRC-024.

Likes 0	
Dislikes 0	

Response

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC

Answer	No
Document Name	

Comment

There does not appear to be a threshold for an element to be applicable under section 4.2.1.5. Since the definition of Element is vague (Any electrical device with terminals that may be connected to other electrical devices…) and there is no generation level specified to trigger the inclusion of an Element per section 4.2.1.5, additional clarity is needed. The BES Definition Inclusion 4 is referenced in section 4.2.1.6, so it may be interpreted that the aggregate 75 MVA threshold should alo be used for section 4.2.1.5, but it is not clear. SRP recommends providing more specific criteria for applicability under section 4.2.1.5.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	
Comment	
Please provide a definition for "generating resource" as used in the document. Would a reactor coolant pump motor or a boiler feed pump motor be considered one as they are both “resources” that are required for generation? If not, how can we assure that an auditor won't think so? Without this, we don’t see how this answers item “f” in the SAR Project Scope to “Clarify that plant auxiliary equipment protection systems are not subject to the requirements of PRC-024”.	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Dominion Energy does not agree that proposed Reliability Standard PRC-024-3 clearly exempts plant auxiliary equipment from the requirements of this standard. While there is some language contained within the Applicability section (4.2.1.3) of proposed Reliability Standard PRC-024-3, we believe it is insufficient to ensure GO’s plant auxiliary equipment is exempt from the requirements of this proposed Reliability Standard. Our proposal to address this issue and other concerns within the Applicability section of PRC-024-3 are provided in our response to Question 11.	
Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	No
Document Name	
Comment	
Agree with EEI.	
Likes 0	
Dislikes 0	

Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	
We do not agree with excluding plant auxiliary equipment from the scope of the standard. Auxiliaries critical to maintain plant output must also be considered. For example, loss of primary heat transport supply to primary heat pumps in a CANDU nuclear design or fuel gas compressors in a gas plant will result in reduced plant output. The supply to other critical auxiliaries like lubricating systems, governing and excitation systems that allow the generating unit to maintain its output level also must meet PRC-024 requirements for reliability. **We would like to better understand the rationale for not applying plant auxiliary equipment to the standard. Having auxiliaries trip too early on voltage or frequency which cause output to change is by definition an interaction between the plant and the power system. If the tripping auxiliaries do not affect P,Q, or Vt of the units at the plant, then we agree with they do not need to be considered.**	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
It is AEP's conclusion that it is not clear that voltage and frequency protection applied to plant auxiliary equipment is not applicable to the standard, due to the proposed inclusion of high side of the generator-connected auxiliary transformer. This could result in an expansion of scope that is not intended by the revisions proposed by the Standards Drafting Team. In addition, more concerning than whether or not plant auxiliary equipment is clearly out of scope of PRC-024, is the inclusion of "High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s)" within 4.2.1.3. We find no technical justification for its inclusion. AEP objects to this inclusion and seeks clarification and justification for proposing it.	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	No

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon agrees that the draft Standard has revised the Applicability to exclude auxiliary equipment from scope; however, Exelon suggests adding further clarification to ensure that there is no potential ambiguity. This could be accomplished in a footnote to the applicability section or noted elsewhere in the Standard. Suggested language is as follows: “Generator trips resulting from auxiliary equipment voltage and frequency protection systems (either directly or via tripping signals) are not included in the scope of PRC-024-3” Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	

Answer	Yes
Document Name	
Comment	
However, Tacoma Power believes there is still room for improving this clarification	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Yes, we agree that plant auxiliary equipment should be excluded. the term, "Bulk Elcetric System (BES) generating resource(s)," in para. 4.2.1.1, combined with, "all or part of," in para. 4.2.1, could undo this exclusion, however, especially when considering our response to question 11 below. The proposed new standard could be interpreted as forbidding drop-out of motor control center contractors, for example.	
Likes 0	
Dislikes 0	
Response	
Matthew McMillan - Talen Generation, LLC - 5	
Answer	Yes

Document Name	
Comment	
Yes, we agree that plant auxiliary equipment should be excluded. The term, “Bulk Electric System (BES) generating resource(s),” in para. 4.2.1.1, combined with, “all or part of,” in para. 4.2.1, could undo this exclusion, however, especially when considering our response to question 11 below. The proposed new standard could be interpreted as forbidding drop-out of motor control center contactors, for example.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
We recommend a footnote that says something to the effect of: “Generator trips resulting from auxiliary equipment protection systems (either directly or via tripping signals) are not included in the scope of PRC-024-3”	
Likes 0	
Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Darko Kovac, Gainesville Regional Utilities, 1, 5, 3; David Owens, Gainesville Regional Utilities, 1, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Nick Batty, Keys Energy Services, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allen Schriver - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shirley Mathew - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio	
Answer	
Document Name	
Comment	
NCEMC supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	

Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	

7. The SDT made several clarifying changes to the figures and tables (outlined in the SAR) to improve readability and eliminate confusion addressed in the SAR, including: (i) labeling the area outside the "No Trip Zone" as the "May Trip Zone;" (ii) removal of "ride-through" language; (iii) addition of "Minimum Time;" (iv) replacement of "instantaneous" with "0.10" seconds; and (v) clarifying modifications to the Voltage Boundary Clarifications. Do you agree with these modifications? If not, please recommend alternative solution(s)

Dan Roethemeyer - Vistra Energy - 5	
Answer	No
Document Name	
Comment	

Please clarify why a change is being made from instantaneous to .10 seconds. They will likely require changes to protection systems and generator owners have likely already completed many reviews of their frequency settings and adding the .10 second requirement could require additional time and resources to review again. Recommend leaving as instantaneous.

Likes 0	
Dislikes 0	
Response	

Leonard Kula - Independent Electricity System Operator - 2	
Answer	No
Document Name	
Comment	

Most power system analysis is done using a positive-sequence representation on the network. By updating the standard to specify the use of positive sequence voltage will make the standard more practical.

We propose that the RMS signal should be clarified that it pertains to positive-sequence. We propose that Item 5 in the section "Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections, Boundary Details [page 21 of 25] be consistent with that for the Quebec Interconnection and be replaced with:

5. Voltages in the boundaries assume positive-sequence values.

instead of the proposed "Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase voltage"

Likes 0	
Dislikes 0	
Response	

Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	No

Document Name	

Comment

Changes to the curves and tables are very helpful.

In Attachment 2, Voltage Boundary Clarifications, how does item 2. “The boundaries apply to voltage excursions regardless of the type of initiating event” provide clarification? I understand the curves were developed based on event simulations, but for analysis, the Entity is simply plotting the relay curves using assumed loading conditions to assure these curves and thus tripping are not in the “No Trip Zone”. If this statement is attempting to tell the Entity that running a series of event simulations is not enough to ensure compliance, please add more information to the clarification.

In Attachment 2, Voltage Boundary Clarifications, item 3 is correct, but is redundant as Table 1 already includes the text “Minimum Time (sec). Should item 3 be removed from the document?

In Attachment 2, Voltage Boundary Clarifications, item 4 states that the boundary can be adjusted in proportion to frequency. Does this eliminate the possibility of leaving the boundary alone and evaluating the volts per hertz relay at 60Hz?

In Attachment 2, Voltage Boundary Clarifications, item 6 is correct, but is redundant as Table 1 indicates no limitation in voltage setting after 4 seconds. Should item 6 be removed from the document.

Likes 0	
Dislikes 0	

Response

Glen Farmer - Avista - Avista Corporation - 5

Answer	No
Document Name	

Comment

agree with EEI.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

In general, Dominion Energy supports most of the clarifying changes made to the figures and tables contained in the proposed Reliability Standard PRC-024-3; however, it appears the boundaries curves depicted assume a system frequency is of 60 Hertz. When evaluating volts per hertz

Volts/Hertz protection, you may adjust the magnitude of the high voltage curve boundary which can be adjusted in proportion to deviations of frequency below 60 Hertz. Dominion Energy suggests that the SDT review the curves and make appropriate modifications.

Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	

Response

David Jendras - Ameren - Ameren Services - 3

Answer	No
Document Name	

Comment

If we have a frequency trip point that is right on the boundary I.e trip freq. at 0.1 seconds, how would this be ruled? Is the relay in compliance or should it be reset so that it is away from the boundary. The comment "Not Including the Lines" was removed from Attachment 1 Figure 1. If the intent is now to include the lines (i.e. the "No Trip Zone" includes the boundary) then rather than remove "Not Including Lines" it would be better to change to "Including the lines".

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	No
Document Name	

Comment

WECC questions the change from “Instantaneous Trip” to 0.10 seconds on the Frequency Boundary Data Points table. Is the 0.10 seconds an intentional delay that must be set on the protection equipment or is it the time that the resource must stay connected. If it is an intentional delay, WECC believes it should be 0.00 seconds. As noted in the Gaps Whitepaper frequency is calculate on a “sliding window” which inherently implements a time delay of 100 ms (6-Cycles). The proposed change stems from an erroneous “perceived system frequency below 57 Hz due inverter-based resources using the Phase Locked Loop logic indicating a near instantaneous frequency during the transient/distorted waveform period as less than 57 Hz” and introduces additional time delay, 6-cycle “sliding window” plus a relay time of 100 ms exposing the units to an effective 12-cycle event. Additionally, this delay could burden industry with unnecessary and time-consuming protection system setting changes to address an erroneous frequency calculation by inverter-based resources. If this is an intentional time delay that must be set, synchronous machine owners may have to reset their protection system setting if it is based on the current version of the standard.

WECC disagrees with the change on the Voltage Boundary Data Points table. Like the frequency tables, where “continuous operation” is specified for frequencies within a certain boundary, WECC believes that “continuous operation” should be specified for voltages between 1.10 pu and 0.90 pu, rather than 4.00 seconds. Why does the no-trip zone end at four seconds? Resource owners could misinterpret this to mean resources may trip or go into momentary cessation after four seconds of operation between 1.10 pu and 0.90 pu. This should also be revised in the Voltage Boundary Clarifications section.

Likes 2	Tarantino Joe On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, ; JEA, 3, Baker Garry
Dislikes 0	

Response

Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC

Answer	No
Document Name	

Comment

The premise of changing the instantaneous trip points to a minimum delay of .10 sec in Attachment 1 is flawed. Reading the SAR, it is saying that frequency cannot and should not be measured or calculated using an instantaneously sampled value, and that the minimum window that should be used is 6 cycles (.1 seconds). While I agree with this statement, I think that it is flawed to add this delay and make the assumption that the relays are not already operating with an internal delay to calculate frequency and rms voltage. The microprocessor based relay is already adding a delay to sample and calculate frequency over a defined window. By adding .1 seconds, as this new revision is proposing, you are actually adding a time delay on top of a time delay that already exists internally during the calculation of frequency. Frequency and RMS are never measured 'instantaneously', and adding a time delay would not fix a relay that is measuring these signals incorrectly.

Likes 0	
Dislikes 0	

Response

Faz Kasraie - Seattle City Light - 5

Answer	No
Document Name	

Comment

Seattle City Light has voted No on this standard due to discrepancies with adding an additional time delay to the frequency settings of the protective relays. Seattle City Light has provided full comments on the Project 2018-04 Modifications to PRC-024-2 | PRC-024-3 (Draft 1) form explaining our position.

Likes 0	
Dislikes 0	

Response

Scott Berry - Scott Berry On Behalf of: Jack Alvey, Indiana Municipal Power Agency, 1, 4; - Scott Berry

Answer	No
Document Name	

Comment	
There is no need to replace instantaneous with 0.10 seconds. If there is a significant event on the system above or below the appropriate set points, the minimum set point should be instantaneous.	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	
NPPD supports the comments submitted by the LPPC (Large Public Power Council)	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	No
Document Name	
Comment	
IID is recommedning that the relay has a minimum delay of 0.08 seconds and adding 0.1 the total time delay will be 0.18 seconds.	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	No
Document Name	
Comment	

I agree with the comments submitted by Sean Bodkin-Dominion	
Likes 0	
Dislikes 0	
Response	
Daniel Mason - Portland General Electric Co. - 6	
Answer	No
Document Name	
Comment	
Recommend that PRC-024 – Attachment 2 Voltage Boundary Data Points table should include high and low voltage limits for the “Continuous operation” zone, as was done for the Quebec Voltage Boundary Data Points and all Frequency Boundary Data Points.	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Addition of intentional delay for thermal units for the low and high frequency ranges are unnecessary. There are inherent time delays associated with an instantaneous protection system tripping scheme that is close to 6-8 cycles (detection time + computation time+ tripping signal transmit time + interrupting device opening time). Including the ‘minimum time delay’ creates additional burden on the synchronous generator owners to revise the settings and test those settings without additional benefits to the reliability of the BES. The proposed revision will be a compliance burden that does not add reliability benefits.	
Likes 0	
Dislikes 0	
Response	
Shirley Mathew - Austin Energy - 5	
Answer	No
Document Name	

Comment	
Addition of intentional delay for thermal units for the low and high frequency ranges are unnecessary. There are inherent time delays associated with an instantaneous protection system tripping scheme which is close to 6-8 cycles (detection time + computation time+ tripping signal transmit time + interrupting device opening time). Including the 'minimum time delay' creates additional burden on the synchronous generator owners to revise the settings and testing those settings without additional benefits to the system. This will be a compliance burden and does not add to reliability benefits.	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Scott Parker - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	No
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	No
Document Name	
Comment	
The revision to Figure 1 to label the area as a "May Trip Zone" is confusing. Exelon suggests explaining that if tripping, trip setpoint(s) need to be set to operate "on or below" the appropriate curve in lieu of labeling the region outside as a "May Trip Zone". This also will provide clarification for settings on the curve are considered compliant. Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	

Answer	No
Document Name	
Comment	
It may be clearer that the “May Trip Zone” be shaded. Also, the standard should continue to explain that the lines are not included in the trip zone in words. The boundary details Note 1, should include the verbiage “…nominal operating voltage at the high-side of the GSU or collector transformer” in order to be consistent and absolutely clear. Boundary Details, Note 4 may be better explained with an example.	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
Do not completely agree. The 0.1 second delay proposal is included to address an incorrect frequency calculation method used by inverter manufacturers. With a correction to the frequency calculation method already made, it is note clear why this change is needed. Also, the wording of the purpose, facilities, and requirements effectively add plant "ride-through" obligations to the GO and the TO rather than addressing the protection system settings solely. To better express the intention of the "No Trip Zone" in Attachment 2 and 2a, the phrase "…represent the minimum time durations allowed…" in Note 3 of the Voltage Boundary Clarifications section should be "….represent the minimum time duration required for no trip from the protection settings …."	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	No
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

Comments: Kansas City Power & Light Company and Westar endorses comments submitted by EEI member companies.

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed

Answer	No
Document Name	

Comment

Most power system analysis is done using a positive-sequence representation on the network. By updating the standard to specify the use of positive sequence voltage will make the standard more practical.

We propose that the RMS signal should be clarified that it pertains to positive-sequence. We propose that Item 5 in the section “Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections, Boundary Details [page 21 of 25] be consistent with that for the Quebec Interconnection and be replaced with:

5. Voltages in the boundaries assume positive-sequence values.

instead of the proposed “Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase voltage”

Likes 0	
Dislikes 0	

Response

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

Answer	No

Document Name	
Comment	
In general, EEI member companies support most of the clarifying changes made to the figures and tables contained in the proposed Reliability Standard PRC-024-3; however, the changes made to the tables supporting the various graphs contained in Attachment 1 (Frequency No Trip Boundary by Interconnection), as it relates to the change from “Instantaneous trip” to “0.10” seconds may create confusion. While we understand and support what the SDT has attempted to do (i.e., removal of the instantaneous trip label from the table), , we believe that the clarifying changes may be interpreted to mean an additional 0.10 second (i.e., approx. 6 cycle) delay is now required after a measurement of frequency greater than 66Hz or below 55.5Hz has been measured. For this reason, we suggest leaving the Instantaneous trip language within the underlying tables and simply adding a note to explain the 100ms filtering/time window is needed to accurately measure frequency and that no intentional time delay is required. This change would more clearly convey the intent and retain consistency between the frequency tables and the voltage table in Attachment 2, as well as, ensure that both traditional resources and inverter-based resources consistently operate and understand the intent.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC	
Answer	No
Document Name	
Comment	
We suggest changing the “May Trip Zone” to an “Equipment Limitation Zone” to ensure that the generator will remain connected to the system for the longest time allowed by the equipment capabilities that are outside the “No Trip Zone”. In addition, the SDT should consider and specify what is required after four seconds. As currently drafted, the Voltage No-Trip Boundary chart on page 19 ends at four seconds. Transient conditions may last longer than four seconds. What should the requirement be after four seconds, and for how long? There should be some certainty beyond four seconds – what is continuous rating (i.e.- the Quebec chart)?	

Since most power system analysis is done using a positive-sequence representation on the network, updating the standard to specify the use of positive sequence voltage will make the standard more practical.

We propose that the RMS signal should be clarified that it pertains to positive-sequence. We propose that Item 5 in the section "Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections, Boundary Details [page 21 of 25] be consistent with that for the Quebec Interconnection and be replaced with:

"*5. Voltages in the boundaries assume positive-sequence values*."

Rather than the proposed "*Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase voltage"*

If the language is to remain as is then please correct a typo in the Eastern Interconnection Boundaries chart on page 15—"May Trip" Zone should be "May Trip Zone" in order to be consistent with the use of the phrase elsewhere in the proposed Standard.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	No
Document Name	

Comment

OPG supports RSC's comments.

Likes 0	
Dislikes 0	

Response

Bradley Collard - SunPower - 5

Answer	No
Document Name	

Comment

SunPower believes the SDT may want to revisit the frequency and voltage protective relay functions found in their documentation. Removing the term “Instantaneous trip” with “0.10” will require many protective relay functions to be changed on relays across all Interconnections that are not the real issue at the core of the SAR.

Also, provide language that allows instantaneous tripping of inverter control protection if any protection relay has operated seperating the inverter from the system.

Likes 0	
Dislikes 0	

Response

RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

The revision to Figure 1 to label the area as a “May Trip Zone” is confusing. Suggest explaining that trips need to be set to operate “on or below” the appropriate curve in lieu of labeling the region outside as a “May Trip Zone”. This also will provide clarification for settings on the curve are considered compliant.

Likes 0	
Dislikes 0	

Response

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

Answer	Yes
Document Name	

Comment	
None	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
We also submit the following modifications to Chart Attachment 1: Y axis (Time) should continue below 0.1 second down to 0 seconds. The drafting team is aware of this shortcoming due to the logarithmic chart. Consider using a chart with a discontinuity symbol to allow for an axis break on the Y axis so that a portion of the chart ranges from 0 to 0.1 second and a portion ranges from 0.1 to 10,000 seconds. The associated table should reflect the changes to the chart and should clarify acceptable trips below 0.1 seconds.	
Likes 1	JEA, 3, Baker Garry
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
It may be beneficial for the Voltage No-Trip Boundary to show a vertical line at 4 seconds to indicate the end of the “No Trip Zone” of the Voltage No-Trip Boundary – Eastern, Western, and ERCOT Interconnections. This change would align with bullet point 6 in the Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections. Regarding the implementation period associated with the proposed 0.1-second time delay, given the current instantaneous trip has been in place for several years with no identified impact on the bulk power system it is suggested that the SDT consider a longer implementation period for any necessary changes that are less than the proposed time delay of 0.1-seconds. Since the instantaneous settings has been in place and implemented for several years (20+ years) the proposed 18-month period may be problematic for some as it requires changes to the trip settings and any necessary testing associated with that proposed change.	

Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew McMillan - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kayleigh Wilkerson - Lincoln Electric System - 5, Group Name Lincoln Electric System	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Chua - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allen Schriver - NextEra Energy - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Batty - Keys Energy Services - NA - Not Applicable - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Darko Kovac, Gainesville Regional Utilities, 1, 5, 3; David Owens, Gainesville Regional Utilities, 1, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Nick Batty, Keys Energy Services, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Leo Bernier - AES - AES Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio	

Answer	
Document Name	
Comment	
NCEMC supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	

8. The SDT added Quebec Interconnection-wide Variance to Requirement R2 with more stringent voltage boundaries for the No Trip Zone. Do you agree with this proposed Quebec Variance? If not, please provide your rationale

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

Answer	No
Document Name	

Comment

We believe that the variance language can be sufficientlly and effectively handled in the Quebec Interconnect specific figure similar to the frequency "no trip zone" Quebec specific chart and that a separate variance section is not required.

Likes 0	
Dislikes 0	

Response

Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5

Answer	Yes
Document Name	

Comment

I am in agreement with comments submitted by Sean Bodkin-Dominion.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1

Answer	Yes
Document Name	

Comment

Exelon does not own any facilities in the Quebec Interconnection so has no opinion on this revision.

Exelon, Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority - 6	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Allen Schriver - NextEra Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Scott Parker - SCANA - South Carolina Electric and Gas Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shirley Mathew - Austin Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	

Response

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio

Answer	
Document Name	

Comment

NCEMC supports the comments submitted by ACES

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	
Document Name	

Comment

The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)

Likes 0	
Dislikes 0	

Response
Leo Bernier - AES - AES Corporation - 5
Answer	
Document Name	
Comment
AES is not part of the Quebec Varience so has no comment.
Likes 0	
Dislikes 0	
Response
Bette White - AES - Indianapolis Power and Light Co. - 3
Answer	
Document Name	
Comment
IPL is not part of the Quebec region
Likes 0	
Dislikes 0	
Response
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI
Answer	
Document Name	
Comment
AECI supports the comments submitted by ACES
Likes 0	
Dislikes 0	
Response

Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	
Document Name	
Comment	
NA	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	
Document Name	
Comment	
No comment, as this Variance does not apply to LDWP.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	
Document Name	
Comment	
Texas RE does not have comments on the question.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	

Document Name	
Comment	
Abstain.	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	
Document Name	
Comment	
N/A	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
We have no opinion on the Quebec Variance.	
Likes 0	
Dislikes 0	
Response	
Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	
Document Name	
Comment	

Abstain.	
Likes 0	
Dislikes 0	
Response	
Matthew McMillan - Talen Generation, LLC - 5	
Answer	
Document Name	
Comment	
Abstain – we are not in the Quebec Region.	
Likes 0	
Dislikes 0	
Response	

9. Do you agree with the proposed Implementation Plan? If not, please provide your rationale	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
AEP disagrees with the proposed revisions which expand the scope of this standard. We believe that 18 months is insufficient, especially in regards to impacts associated with a) changing, albeit unintentionally, the historically recognized “Point of Interconnection” as the reference point of compliance and b) the inclusion of applicable functions on the high-side of generator-connected auxiliary transformers. AEP suggests that the proposed implementation plan be increased to 36 months as the proposed changes would redefine the entire scope of the work performed to date.	
Likes 0	
Dislikes 0	
Response	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	No
Document Name	
Comment	
With the current lack of understanding of the behavior of existing installed equipment with regard to “momentary cessation”, and the resulting required interaction with manufacturers and then implementing any necessary changes, 18 months does not seem to be a sufficient amount of time.	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
What is the basis for the Compliance Dates in the Implementation Plan, i.e. 18-months for GOs and 60-months (18-months plus 42-months) for TOs? If changes are required, many facilities can’t make them that quickly as they have to 1) obtain funding for and perform an analysis to see if they have compliance gaps and, if so, 2) obtain funding for the change(s), 3) complete a design for the change(s), and 4) implement the changes which will likely require an outage that can be as much as two years in the future. The original dates for version 1 (and 2) were	

phased in over a longer period. Please provide a longer time for compliance along the lines of the earlier versions or, at least, give the GOs the same 60-month time frame as the TOs.

Likes 1	Tarantino Joe On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6,
Dislikes 0	

Response

Lana Smith - San Miguel Electric Cooperative, Inc. - 5

Answer	No
Document Name	

Comment

We believe 18 months may not be sufficient for GOs to verify the setting based upon to the proposed changes in the SAR. As an example, replacing "instantaneous" language with "0.10 second" requires entities to verify the existing setting to meet this requirement. Cost Impacts are an important aspect to be studied. Considerations of estimated time-extensions cost impacts and company budget cycles is requested to be measured in the time-extension decisions.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

There may be substantial retesting and replacements to comply with this proposed Standard. The NSRF recommends a 24 month implementation plan as this will give Entities planning time for maintenance outages and for budget forecasting purposes.

Likes 0	
Dislikes 0	

Response

Alex Chua - Pacific Gas and Electric Company - 1,3,5

Answer	No
Document Name	

Comment

A longer implementation plan should be provided when relay replacements or control upgrades are required.

Likes 0	
Dislikes 0	

Response

Scott Berry - Scott Berry On Behalf of: Jack Alvey, Indiana Municipal Power Agency, 1, 4; - Scott Berry

Answer	No
Document Name	

Comment

The way the current draft is written and the possible inclusion of new equipment and systems, entities should be given more time. Generator Owners should be given 36 months from the time the standard is approved by FERC to become compliant with the current drafted requirements. This would allow for communication with the appropriate parties to see how systems would react to the current proposed set points and maybe allow any applicable modeling that may be required. If the standard was truly just adding solar plant inverters, the current proposed implementation plan would be sufficient.

Likes 0	
Dislikes 0	

Response

Don Schmit - Nebraska Public Power District - 1,3,5

Answer	No
Document Name	

Comment

NPPD suppports the comments submitted by the MRO NSRF.

Likes 0	
Dislikes 0	

Response

Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy

Answer	No
Document Name	

Comment

Duke Energy recommends a 24 month implementation timeframe that would allow sites to better plan their outages, costs and resources for this change.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
Propose to change the implementation plan time to 42 months. The current instantaneous trip allowance for Synchronous generator has been in place for several years with no identified impact on the bulk power system. Austin Energy suggests the SDT consider a longer implementation period than 18 months for the necessary protection scheme changes, implementation and testing of the protection systems associated with the new requirement.	
Likes 0	
Dislikes 0	
Response	
Shirley Mathew - Austin Energy - 5	
Answer	No
Document Name	

Comment
Propose to change the implementation time to 42 months. The current instantaneous trip allowance for Synchronous generator has been in place for several years with no identified adverse impact on the bulk power system. It is suggested that the SDT consider longer implementation period than 18 months for the necessary protection scheme changes, implementation and testing of the protection systems associated with the new requirement.

Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	

Response

Allen Schriver - NextEra Energy - 5	
Answer	No
Document Name	

Comment
Comments: As stated in the response to question #5, transmission asynchronous interties exhibit the same momentary cessation issues due to voltage and frequency excursions as solar inverters, (see the Pacific DC Intertie information in the WECC May 11, 2018 event report). This is no less an issue for protecting reliability, but transmission owners will be provided approximately 60 months to fully comply. The costs associated with implementation can be incorporated into their tariff rates; therefore, transmission owner will not be effected economically.

Likes 0	
Dislikes 0	

Response

Chris Scanlon - Exelon - 1	
Answer	No
Document Name	

Comment
Nuclear generating units typically run continuously and therefore implementation would have to be done during a scheduled refueling outage (typically 2 years for a boiling water reactor and 18 months for a pressurized water reactor). The scheduling to implement design changes during refueling outages is typically scoped at least 24 months in advance. The current draft of the PRC-024-3 implementation plan states that the Standard shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the effective date of the applicable governmental authority's order approving the Standard. The original dates for Version 1 (and 2) were phased in over five calendar years. Exelon requests that the effective date for Generator Owners be extended to the same 60-month time frame afforded the Transmission Owners to allow reasonable time for a nuclear generating unit to evaluate and implement any necessary design changes during a planned refueling outage. Exelon, Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Eighteen months is relatively short duration to make changes to embedded protection systems for GO when considering an entire fleet. Often these changes may need to follow unit outage schedules. The implementation plan should provide additional time for this requirement as a result of fleet size and the need for scheduled outages. GO/TO timelines should be similar.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

Do not agree with the implementation plan since we do not agree completely with the modified purpose, applicability, facililities, and requirements of this draft version.

Likes 0	
Dislikes 0	

Response

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

Answer	No
Document Name	

Comment

We believe 18 months is not sufficient for GOs to verify the setting based upon to the proposed changes in the SAR. As an example, replacing "instantaneous" language with "0.10 second" requires entities to verify the existing setting to meet this requirement. Cost Impacts are an important aspect to be studied. Considerations of estimated time-extensions cost impacts and company budget cycles is requested to be measured in the time-extension decisions.

Likes 0	
Dislikes 0	

Response

Davis Jelusich - Public Utility District No. 1 of Chelan County - 6

Answer	No
Document Name	

Comment

Replacing the term “protective relays” with “protection” triggers a review of generating resource protection devices, specifically exciter protection functions. While it does not appear to be the intention of the SAR and the SDT’s current draft, other types of voltage and frequency protection devices associated with each generating unit or resource could also potentially fall within scope of PRC-024-3. Consideration should be given to the time required to identify these protections and, if needed, implement appropriate protection setting modifications within the PRC-024-3 Implementation Plan, especially if exclusions of these other protection systems are not provided.

Likes 0	
Dislikes 0	

Response

Anton Vu - Los Angeles Department of Water and Power - 6

Answer	No
Document Name	

Comment

It is suggested that the Implementation Plan allow the Generator Owner an additional six months after the effective date to implement the revised Standard.

Likes 0	
Dislikes 0	

Response

Greg Davis - Georgia Transmission Corporation - 1

Answer	No
Document Name	

Comment

We believe 18 months is not sufficient for GOs to verify the setting based upon to the proposed changes in the SAR. As an example, replacing "instantaneous" language with "0.10 second" requires entities to verify the existing setting to meet this requirement. Cost Impacts are an important aspect to be studied. Considerations of estimated time-extensions cost impacts and company budget cycles is requested to be measured in the time-extension decisions.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No
Document Name	

Comment

Comments: Kansas City Power & Light Company and Westar endorses comments submitted by EEI member companies. In order to better accommodate nuclear power plant refueling and maintenance outages, EEI recommended extension to 18 to 24 months. In some cases depending on the where an entity is in the cycle, this may extend to 36 months. The Implementation plan will need to account for this nuance.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

Comments: There may be substantial retesting and replacements to comply with this proposed Standard. The NSRF recommends a 24 month implementation plan as this will give Entities planning time for maintenance outages and for budget forecasting purposes.

Likes 0	
Dislikes 0	
Response	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	
EEI member companies suggest that the implementation plan be extended from 18 months to 24 months in order to better accommodate nuclear power plant refueling and maintenance outages which generally occur on 18 to 24 month intervals.	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC supports the comments submitted by the Edison Electric Institute.	
Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
For a nuclear generating unit implementation would have to be during a scheduled refueling outage (typically 2 years for a boiling water reactor and 18 months for a pressurized water reactor). The scheduling for such outages is typically scoped at least 6 months in advance. The current draft of the PRC-024-3 implementation plan states that the Standard shall become effective on the first day of the first calendar quarter that is eighteen (18) months after the effective date of the applicable governmental authority's order approving the Standard. We request that this effective date be extended to 24	

months following the effective date to allow reasonable time for a nuclear generating unit to evaluate and implement any necessary design changes during a planned refueling outage.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
The changes in the implementation plan do not affect IPL.	
Likes 0	

Dislikes 0	
Response	
Bradley Collard - SunPower - 5	
Answer	Yes
Document Name	
Comment	
Yes, but with some reservation. Depending on changes that must be done on inverters and the availability of inverter manufacturer resources to make those changes, coupled with the amount of work that may apply to protective relays with the new 0.10 trip setting, the Requirement may present challenges. The time allowed to conduct an analysis, budget the work, and schedule the work with the appropriate resources could push the bulk of the work in the last 12 to 6 months of the timeline. That may present scheduling challenges with limited industry resources. Consider allowing 24 months if both protective functions and inverter functions need to be changed.	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Matthew McMillan - Talen Generation, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	Yes
Document Name	
Comment	
Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - NA - Not Applicable - FRCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Darko Kovac, Gainesville Regional Utilities, 1, 5, 3; David Owens, Gainesville Regional Utilities, 1, 5, 3; Don Cuevas, Beaches Energy Services, 1, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Neville Bowen, Ocala Utility Services, 3; Nick Batty, Keys Energy Services, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Steven Lancaster, Beaches Energy Services, 1, 3; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Joe Tarantino - Joe Tarantino On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Beth Tincher, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Jamie Cutlip, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Kevin Smith, Balancing Authority of Northern California, 1; Nicole Looney, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; Susan Oto, Sacramento Municipal Utility District, 4, 1, 5, 6, 3; - Joe Tarantino	
Answer	
Document Name	
Comment	
Regarding the implementation period associated with the proposed 0.1-second time delay, given the current instantaneous trip has been in place for several years with no identified impact on the bulk power system it is suggested that the SDT consider a longer implementation period for any necessary changes that are less than the proposed time delay of 0.1-seconds. Since the instantaneous settings has been in place and implemented for several years (20+ years) the proposed 18-month period may be problematic for some as it requires changes to the trip settings and any necessary testing associated with that proposed change.	
Likes 2	Snohomish County PUD No. 1, 3, Chaney Holly; Public Utility District No. 1 of Snohomish County, 1, Duong Long
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	

Document Name	
Comment	
Texas RE requests justification for timeframe described in the Implementation Plan.	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	

The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)

Likes 0	
Dislikes 0	

Response

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio	
Answer	
Document Name	

Comment
NCEMC supports the comments submitted by ACES

Likes 0	
Dislikes 0	

Response

10. Do you agree that the proposed modifications provide a cost-effective means of addressing issues in the SAR? If not, please provide an alternative, more cost-effective manner in which to achieve at least an equivalent level of reliability

Bradley Collard - SunPower - 5

Answer	No
Document Name	

Comment

SunPower does not understand how the longstanding frequency and voltage protective relay functions are now a concern and must be changed from “instantaneous trip” to “0.10” seconds. It seems it will cost many generators extra money for something that is not a concern. If the desire is to have inverters base their tripping in 6 cycles, then say so. Do not add extra work and costs to other generators that is not causing a reliability issue.

SunPower also would like to point out that changes in any protective relay function and/or voltage/frequency control functions on inverters will require additional costs to industry adjusting dynamic models to meet MOD-032 requirements.

NERC should consider older technology that is incapable of making the changes to be grandfathered and to allow for technical exceptions in order to avoid replacement costs of some equipment.

Likes 0	
Dislikes 0	

Response

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6

Answer	No
Document Name	

Comment

The NSRF believes there may be substantial cost associated with this Standard but cannot state exactly what those cost are as this is the first interaction of the proposed Standard. See question 9.

Likes 0	
Dislikes 0	

Response

Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL

Answer	No

Document Name	
Comment	
Comments: Kansas City Power & Light Company and Westar finds the issues being addressed in this revision to add undue administrative burden to entities to prove compliance where the circumstances do not exist. The basis need for these changes is not widely applicable.	
Likes 0	
Dislikes 0	
Response	
Greg Davis - Georgia Transmission Corporation - 1	
Answer	No
Document Name	
Comment	
It is unclear how the cost assessment has been evaluated. We believe the SAR should provide additional clarification on how much cost will be potentially associated with the implementation of the proposed changes in the SAR. As an example, revising "instantaneous" language to "0.10 second" requires entities to verify their existing settings to ensure the accuracy of this timing. Has this been evaluated in the cost assessment? Cost Impacts are an important aspect to be studied. Considerations of estimated time-extensions cost impacts and company budget cycles is requested to be measured in the time-extension decisions.	
Likes 0	
Dislikes 0	
Response	
Jodirah Green - ACES Power Marketing - 1,3,4,5,6 - MRO,WECC,Texas RE,SERC,RF, Group Name ACES Standard Collaborations	
Answer	No
Document Name	
Comment	
It is unclear how the cost assessment has been evaluated. We believe the SAR should provide additional clarification on how much cost will be potentially associated with the implementation of the proposed changes in the SAR. As an example, revising "instantaneous" language to "0.10 second" requires entities to verify their existing settings to ensure the accuracy of this timing. Has this been evaluated in the cost assessment? Cost Impacts are an important aspect to be studied. Considerations of estimated time-extensions cost impacts and company budget cycles is requested to be measured in the time-extension decisions.	

Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	
Comment	
The work being done on industry standards (IEEE P2800) to provide inverter manufacturers with the desired operation of inverter based generating plants will cause new equpiment to be supplied with the ride through characteristics that are desirable. This, coupled with the fact that at least two major events of the past (referenced in the introductory paragraph of this proposed modification) did not cause significant impacts to the western interconnect. We believe that these two facts will unduly cause generator to have to retrofit or modify existing equipment at a significant cost in order to meet the requirements as currently written, where there is not a clear and present danger of the reduction of system reliability.	
Likes 0	
Dislikes 0	
Response	
Allen Schriver - NextEra Energy - 5	
Answer	No
Document Name	
Comment	
Comments: The SDT is assuming that the inverters at older solar facilities can be easily reprogrammed to meet the proposed requirements in an 18-month time period, if at all. There should be a provision for grandfathering, or at least allowing for a phased-in implementation for older solar inverters that have been in operation for a number of years.	
Likes 0	
Dislikes 0	
Response	
Shirley Mathew - Austin Energy - 5	
Answer	No
Document Name	
Comment	

It is not cost effective for Synchronous generator owners to revise, implement and test the relays with the intentional time delay proposed in the standard. Propose not to change the instantaneous trip criteria from the standard.	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Andrew Gallo - Austin Energy - 1,3,4,5,6	
Answer	No
Document Name	
Comment	
It is not cost effective for Synchronous generator owners to revise, implement and test the relays with the intentional time delay proposed in the standard. Austin Energy proposes not changing the instantaneous trip criteria from the standard.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	No
Document Name	
Comment	
Support the MRO NSRF Comments	
Likes 0	
Dislikes 0	
Response	
Don Schmit - Nebraska Public Power District - 1,3,5	
Answer	No
Document Name	
Comment	

NPPD suppports the comments submitted by the MRO NSRF.	
Likes 0	
Dislikes 0	
Response	
Steven Rueckert - Western Electricity Coordinating Council - 10	
Answer	No
Document Name	
Comment	
The potential need for synchronous generator owner to have to reset their protections system settings to address erroneous actions by inverter-based resourse owner is not cost effective.	
Likes 1	Tarantino Joe On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6,
Dislikes 0	
Response	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	No
Document Name	
Comment	
The NSRF believes there may be substantial cost associated with this Standard but cannot state exactly what those cost are as this is the first interaction of the proposed Standard. See question 9.	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	No
Document Name	
Comment	

It is unclear how the cost assessment has been evaluated. We believe the SAR should provide additional clarification on how much cost will be potentially associated with the implementation of the proposed changes in the SAR. As an example, revising "instantaneous" language to "0.10 second" requires entities to verify their existing settings to ensure the accuracy of this timing. Has this been evaluated in the cost assessment? Cost Impacts are an important aspect to be studied. Considerations of estimated time-extensions cost impacts and company budget cycles is requested to be measured in the time-extension decisions.

Likes 0	
Dislikes 0	

Response

Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC

Answer	No
Document Name	

Comment

Put in specific wording on auxiliary equipment not being within scope. Remove the requirements for transformer protection as their addition is not within the scope of the SAR.

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	No
Document Name	

Comment

Until the draft standard is on a final form Dominion Energy cannot comment on the proposed cost effectiveness.

Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	No
Document Name	

Comment	
Confusion caused by the concerns we are stating could render PRC-024-3 non-cost-effective.	
Likes 0	
Dislikes 0	
Response	
Matthew McMillan - Talen Generation, LLC - 5	
Answer	No
Document Name	
Comment	
No. Confusion caused by the concerns we are stating could render PRC-024-3 non-cost-effective.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	

As discussed above, AZPS respectfully notes that the proposed modifications shift both cost and compliance responsibility for generator protection to TOs without explanation or justification. For this reason, AZPS is concerned that the modifications would not be cost-effective.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Leo Bernier - AES - AES Corporation - 5

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed

Answer	Yes
Document Name	

Comment

Likes 0	
Dislikes 0	

Response	
Bette White - AES - Indianapolis Power and Light Co. - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anton Vu - Los Angeles Department of Water and Power - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Savin - New York Power Authority - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Scott Langston - Tallahassee Electric (City of Tallahassee, FL) - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Jesus Sammy Alcaraz - Imperial Irrigation District - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Alex Chua - Pacific Gas and Electric Company - 1,3,5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ozan Ferrin - Tacoma Public Utilities (Tacoma, WA) - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Gerry Huitt, Xcel Energy, Inc., 3, 1, 5; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Eric Smith - NaturEner USA, LLC - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC	
Answer	
Document Name	
Comment	
The IRC SRC submits no response to this question.	
Likes 0	
Dislikes 0	
Response	
Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio	
Answer	
Document Name	
Comment	
NCEMC supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	

Richard Vine - California ISO - 2	
Answer	
Document Name	
Comment	
The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	
Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	

Answer	
Document Name	
Comment	
Texas RE does not have comments on the question.	
Likes 0	
Dislikes 0	
Response	
Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1	
Answer	
Document Name	
Comment	
I agree with the comments submitted by Sean Bodkin-Dominion	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
SCANA- South Carolina Electric and Gas (Dominion Energy South Carolina) is in agreement with comments form Sean Bodkin (Dominion Energy).	
Likes 0	
Dislikes 0	
Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	
Document Name	

Comment
With the exception of the removal of instantaneous tripping, I agree. If there is a concern with how the industry is measuring RMS, frequency, filtering, and other time varying signals that require filtering and a sample window, then we should possibly be mandating minimum specification requirements for protective relaying equipment, or standardizing how we are testing the relay elements to ensure they performing as expected.

Likes 0	
Dislikes 0	

Response

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

Comment
As we progress with new site development, we've been adding AVR options such as voltage droop, WindFREE (no load VAR generation) and WindRESERVE (production on units above nameplate, but will aggregate no more than GIA/power curtailment limit). How does this play into relay settings? Particularly from a dispersed generator perspective.

Likes 0	
Dislikes 0	

Response

11. If you have any additional comments on themes that have NOT already been addressed in the proceeding questions on this comment form, please provide them here

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric

Answer	
Document Name	

Comment

none at this time.

Likes 0	
Dislikes 0	

Response

Matthew McMillan - Talen Generation, LLC - 5

Answer	
Document Name	

Comment

Supplemental issue #1 - The original draft of PRC-024-1 included, “shall not trip,” language, which was replaced by, “set its protective relaying,” after GOs pointed-out that we can control our relay settings, but no one knows what might happen to take units offline for the massive disturbances of PRC-024 Att. 1 and 2 (High/low drum level? High/low furnace pressure? CTG flame-out). PRC-024-3 has undone this pivotally important clarification by requiring that protection be set, “such that the generating resource does not trip.” Units may trip regardless of how we set the protection for reasons that are out of scope for the standard and beyond our control. Many CTG protectives in particular are set by the OEM, and often can’t be viewed by plant personnel much less adjusted. The, “set its protective relaying,” language of PRC-024-2 should be retained.

Supplemental issue #2 - The new Voltage Boundary Detail #4 statement, “The boundaries assume a system frequency of 60 Hertz. When evaluating volts per hertz protection, magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz,” is self-contradictory. How can we adjust the voltage boundary for frequency changes, per the second sentence, if the frequency is fixed at 60 Hertz per the first sentence?

Likes 0	
Dislikes 0	

Response

Jennifer Hohenshilt - Talen Energy Marketing, LLC - 6

Answer	
Document Name	

Comment

Supplemental Issue #1 - The original draft of PRC-024-1 included, "shall not trip," language, which was replaced by, "set its protective relaying," after GOs pointed out that we can control our relay settings, but no one knows what might happen to take units offline for the massive disturbances of PRC-024 Att.1 and 2 (High/low drum level? High/low furnace pressure? CTG flame-out). PRC-024-3 has undone this pivotally important clarification by requiring that protection be set, "such that the generating resource does not trip." Units may trip regardless of how we set the protection for reasons that are out of scopefor the standard and beyond our control. Many CTG protectives in particular are set by the OEM, and often can't be viewed by plant personnel much less adjusted. The, "set its protective relaying," language of PRC-024-2 should be retained.

Supplemental Issue #2 - The new Voltage Boundary Detail #4 statement, "THe boundaries assume a system frequency of 60 Hertz. When evaluating volts per hertz protection, magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz," is self-contradictory. How can we adjust the voltage boundary for frequency changes, per the second sentence, if the frequency is fixed at 60 Hertz per the first sentence?

Likes 0	
Dislikes 0	

Response

Jonathan Robbins - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer	
Document Name	

Comment

1.

i. In section 4.2.1.3, can the drafting team more clearly describe a generator-connected unit auxiliary transformer? Is this merely a unit auxiliary transformer that has a high-side connection at the same voltage of a BES generator located at the same plant?

ii. If a start-up transformer can support station load during times when the unit auxiliary becomes inoperable, e.g., emergencies, is this Standard applicable to the start-up transformer?

iii. NERC has provided a definition of a Protection System that appears to not include control systems. Seminole requests that the team review the impact of modifying the definition of Protection System to potentially include control systems and provide potential changes to all impacted Standards as a unified initiative.

iv. It’s unclear in Attachments 1 and 2 whether the lines are in the No Trip Zone of the May Trip Zone. Can the Standard Drafting Team (SDT) please clarify?

v. Seminole reads Attachment 1, Table 1, to not apply to any protection system settings less than 0.10 seconds. For example if we had a setting at .08 sec. that was in the no trip zone, this would not be applicable to this standard, Is this correct?

vi. In Attachment 1, the low frequency (Hz) values are less than or equal signs until the final frequency. For Attachment 2, the low voltage (pu) points are less than signs with the final voltage being less than or equal. Why is this different? Should we be treating the boundary lines differently between attachments?

vii. In the PRC-024-3 Summary of Key Changes document, in the Applicability Section, the second bullet states that voltage and frequency protection should be applied to both GSU and collector transformers. Can this be modified to state something more akin to that if frequency and/or voltage protection is enabled, this protection is applicable? The way it reads is that an entity may be required to enable all applicable frequency and voltage protection on this equipment.

viii. The “Evaluating Protection Settings” section should be modified to coincide with the operating conditions of the generator. The power factor designation should be adjusted to align with whether the generator is underexcited or overexcited. Also, the language should be modified so that it clearly states that an entity may use steady state analysis for a dynamic situation.

ix. PRC-024-2 footnote 1 specifically instructed entities to evaluate the V/Hz protection at nominal frequency (60 Hz). In the PRC-024-3 version, this detail was lost the translation of the footnotes into the facilities/requirements section. This will create ambiguity and may cause entities to believe they have to perform dynamic simulations to show compliance with V/Hz protection schemes.

Likes 0	
Dislikes 0	

Response

Thomas Foltz - AEP - 5

Answer	
Document Name	

Comment

AEP appreciates the work of the Standards Drafting Team and believes much of the proposed revisions to the Attachments would be very beneficial, however we have chosen to cast Negative ballots on the proposed revisions due to our concerns as expressed above. Chief among these concerns are replacing “at the point of interconnection,” with “at the high side of the generator step-up or collector transformer” as well as the inclusion of “High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s)” within 4.2.1.3.

Comments Regarding Summary of Key Changes Document:

Regarding the bullet point “Specifies that voltage and frequency protection should be applied to both generator step-up (GSU) and collector transformers,” AEP recommends this bullet point be reworded to refer to *any* voltage or frequency protection that may happen to exist rather than prescriptively stating that voltage and frequency protection should be applied. As currently written, it appears too much like a recommendation to apply V and Hz protection. We suggest revising this key changes document to benefit future comment and balloting periods, as necessary.

Additional Comments Regarding Revised Standard:

Suggest revising Purpose from “To set generator protection such that generating resource(s) remain connected, continuing to support the BES during defined frequency and voltage excursions” to instead state “To ensure generator protection *is set* such that generating resource(s) remain connected *and continue to support* the BES during defined *durations of off-nominal frequency and voltage.*”

Suggested revisions to Voltage Boundary Clarifications Attachment:

Section Title: Change from to “Voltage Boundary Clarifications” to instead state “Voltage *and Frequency* Boundary Clarifications”

Item 2: Change from “The boundaries apply to voltage excursions regardless of the type of initiating event” to instead state “The boundaries apply to *off-nominal* voltage *and frequency durations* regardless of the type of initiating event.”

Item 3: Change from “The values in the tables represent the minimum time durations allowed for specified voltage excursion thresholds” to instead state “The values in the tables represent the minimum time durations *required* for specified voltage thresholds.” It may still be advantageous to retain the example here because it is too easy to misconstrue the boundaries as meaning no trip for excursions that remain within the boundaries rather than no trip for time durations at the defined levels.

Item 4: Change from “The boundaries assume a system frequency of 60 Hertz” to instead state “The boundaries assume a system *base* frequency of 60 Hertz.” Also, please add a “the “to the second sentence to state “When evaluating volts per hertz protection, *the* magnitude of the high voltage boundary can be adjusted in proportion to deviations of frequency below 60 Hertz.”

Item 5: Change “Voltages in the boundaries assume RMS fundamental frequency phase-to-ground or phase-to-phase voltage” to instead state “Voltage boundaries assume *per unit* RMS fundamental frequency phase-to-ground or phase-to-phase voltage.”

Likes 0	
Dislikes 0	

Response

Leonard Kula - Independent Electricity System Operator - 2

Answer	
Document Name	

Comment

We congratulate the SDT on making practical improvements, like replacing POI with the high side of the main output transformers, to this standard. We believe that the standard can improve reliability by including plant auxiliary equipment in the scope (please see Comment #6).

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

BPA supports USBR's comments regarding R3 and R4:

"In the interest of developing completely clear, unambiguous, grammatically correct Requirements, R3 could be better stated as:

Each Generator Owner or Transmission Owner shall document each known regulatory or equipment limitation1 that prevents an applicable generating resource(s) (unit) with generator frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2. Documentation includes (but is not limited to) study results, experience from an actual event, or manufacturer's advice

The comment above can also be applied to R4. R4 is not very clear and may be providing an opportunity for entities to manipulate information to avoid complying. Recommend rewriting to clear up when and what processes allow for deviation from transmitting the setting information."

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The Title is "Generator Frequency and Voltage Protection Settings", yet the Facilities include GSU and collector transformers and Elements utilized in aggregation of dispersed power producing resources. Should the Title provide some indication that the Standard addresses more than just relaying at the generator? Note that not all voltage or frequency relaying at the Facilities is for the purpose of protecting the generator. For example, Volts per Hertz may be applied at the transformer high voltage side to protect the transformer. Operation of the V/Hz relay would remove the transformer and the connected generator(s) from service.

The Purpose is "To set generator protection, such that generating resource(s) remain connected…". The Facilities include GSU and collector transformers and Elements utilized in aggregation of dispersed power producing resources. Should the Purpose provide some indication that the Standard addresses more than just relaying at the generator? Also, the Facilities include more than just generating resource(s). Should the Purpose include dispersed power producing resources?

Facilities 4.2.1 includes "Frequency, voltage or volts per hertz protection including frequency or voltage protective functions within control systems". This specifically calls out volts per hertz protection, but then assumes the reader will understand that the exciter volts per hertz protective function (tripping) is a voltage protective function. Would it be better to specifically mention the volts per hertz protective function within control systems?

Facilities 4.2.1 states "…that provide tripping or momentary cessation signals to all or part of the generating resource". Currently only 4.2.1.1 is identified as being a generating resource. Should the statement be modified to include all or part of the dispersed power producing resources?

Facilities 4.2.1.5 makes reference to "the dispersed power producing resources". Is it clear that this is referring to the dispersed power producing resources of Facilities 4.2.1.4? Would it be better to provide a complete description of the applicable dispersed power producing resources in 4.2.1.5?

In Attachment 2, Evaluating Protection Settings, item 1. d. includes the assumption "The automatic voltage regulator is in automatic voltage control mode". If calculations are on the static case for steady state initial conditions, how does the automatic voltage regulator control mode come into play? Should item 1. d. be removed from the document?

Likes 0	

Dislikes 0	

Response

Sergey Kynev - Siemens - Siemens Energy, Inc. - NA - Not Applicable - NA - Not Applicable

Answer	
Document Name	

Comment

Likes 0	
Dislikes 0	

Response

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion

Answer	
Document Name	

Comment

Dominion Energy finds the Applicability section of proposed Reliability Standard PRC-024-2 to be confusing and overly complex. While we appreciate SDT efforts to be thorough, we do not believe that that references to the BES definition inclusions or exclusions are needed. We also do not see a need for the inclusion of underlying facilities associated with the applicable protection systems (e.g., GSUs, generating resources, auxiliary transformers, dispersed power producing resources, and collector transformers). For this reason, we offer the following as an alternative for SDT consideration, which we believe accomplishes the same goal more efficiently.

4. Applicability

4.1. Functional Entities

4.1.1 Generator Owners

(*Dominion Energy disagrees with including TOs*)

4.2 Exemptions

4.2.1 Plant auxiliary equipment protection systems

4.3 Facilities

4.3.1 Generator frequency protective relays (or functionally equivalent devices contained within a generating resource's control system)

4.3.1 Generator voltage protective relays (or functionally equivalent devices contained within a generating resource's control system)	
Likes 1	SCANA - South Carolina Electric and Gas Co., 1,3,5,6, Shumpert RoLynda
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	
The title of the standard is "Generator Frequency and Voltage Protection Settings" and the Purpose is "To set generator protection..." Based on this, what is the basis for expanding the scope to include GSUs and unit auxiliary transformers as shown in 4.2.1.2 and 4.2.1.3? We don't see anything in the SAR that includes adding their protection.	
Likes 0	
Dislikes 0	
Response	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
SRP requests some additional clarification for R1. Originally PRC-024-2 listed exceptions were it is permissible to trip in the "no trip zone"(out of step or loss of field functions). Why were some exceptions removed and only the documented and communicated equipment limitations remain?	
Likes 0	
Dislikes 0	
Response	
Lana Smith - San Miguel Electric Cooperative, Inc. - 5	
Answer	
Document Name	
Comment	

SMEC appreciates the efforts of the SDT and the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Michelle Amarantos - APS - Arizona Public Service Co. - 1

Answer	
Document Name	

Comment

Please modify Attachment 2, Evaluation Protection Settings, number 1. c. as follows, because there is no realistic scenario where the high side voltage will be 1.1 pu or higher and the generator voltage will be at 0.95 pf lagging. It is most realistic to use lagging pf for low voltage conditions and leading pf for high voltage conditions.

For low voltage protection use Power factor is 0.95 lagging (i.e. supplying reactive power to the system) as measured at the generator terminals. For high voltage settings use Power factor is 0.95 leading (i.e. taking reactive power from the system) as measured at the generator terminals.

AZPS also reiterates concern with the addition of the TO as an applicable entity shifting compliance and cost responsibility from the GO/GOPs to TO/TOPs, which are distinct, separate entities.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

The NSRF has the following recommendations:

The SDT could consider the following modification to Section 4.2 to add clarity (strikethough is deleted text while italics is added text):

4.2. Facilities:

4.2.1 Frequency, voltage or volts per hertz protection *relays, software controls, firmware controls*, including frequency or voltage protective functions within control systems that provide tripping or momentary cessation signals to all or part of the generating resource, applied to the following:

4.2.1.1 Bulk Electric System (BES) generating resource(s).

4.2.1.2 BES GSU transformer(s).

4.2.1.3 High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s). *Aux transformers that are connected between the high side terminals of the generator's GSU and the BES Interconnection. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online. These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running.*

4.2.1.4 Individual d *D*ispersed power producing resources identified in the BES Definition, Inclusion I4.

4.2.1.5 Elements utilized in aggregation of the dispersed power producing resources. (Rationale comment - covered in 4.2.1.4).

4.2.1.6 Collector transformer of resources identified in the BES Definition, Inclusion I4. (Rationale comment - What transformers are these? If they are part of the <100kV collector system then they are out of scope. Per I4, there is no indication of "collector transformer(s)". If this is the GSU then it is covered in 4.2.1.2.)

Proposed requirement R4: In keeping with the intent of the current Standards Efficiency Review Project, R4 is not required within the proposed Standard as the capturing of data is redundant. The NSRF believes this can be captured under currently enforceable MOD-032-1, R2 which requests data developed by the PC and TP in R1.

Per the webinar, the SDT stated that Facilities 4.2.1.5 "Elements utilized in aggregation of the dispersed power producing resources" reads the same as PRC-025-2. The NSRF disagrees with this statement. This SDT is now expanding both PRC-025-2 and proposed PRC-024-3 to include items that make up the "collector systems", which is directly against the FERC Approved definition of Inclusion I4. When the SDT states 4.2.1.5 is directly related to PRC-025-2 and has the same intentions, the NSRF strongly disagrees. When applying the FERC approved definition of Inclusion I4 and 4.2.1.5 of PRC-024-3 (or PRC-025-2) collector system items ARE NOT applicable to either Standard.

Likes 0	
Dislikes 0	

Response

Steven Rueckert - Western Electricity Coordinating Council - 10

Answer	
Document Name	

Comment

It may have been the intent of the drafting team to make changes so that the standard was technology neutral, but the potential requirement for synchronous generator owner to have to make change that were never necessary in the past, to address an issue with the inverter-based resources does not seem technology neutral.

Likes 1	Tarantino Joe On Behalf of: Arthur Starkovich, Sacramento Municipal Utility District, 4, 1, 5, 6,
Dislikes 0	

Response

Alex Chua - Pacific Gas and Electric Company - 1,3,5

Answer	

Document Name	
Comment	

Footnote 5 : "Excludes limitations that are caused by the setting capability of the generator frequency and voltage protection relays themselves but does not exclude limitations originating in the equipment that they protect"

An older generator uses an electromechanical auxiliary relay for undervoltage protection. It is original equipment installed with the facility more than 30 years ago. There are no settings available on this relay. Similar to other auxiliary relays, when voltage dips below the drop out voltage, contacts would latch and trip the unit. The dropout characteristic of his relay does not meet PRC-024.

Would this case be considered an equipment limitation for PRC-024? We believe it does as it is original equipment with the plant and there is no language in the existing standard stating that new equipment needs to be installed. When new equipment is required (e.g. PRC-002 and PRC-025), a longer implementation period is accounted for.

Likes 0	
Dislikes 0	
Response	

Scott Berry - Scott Berry On Behalf of: Jack Alvey, Indiana Municipal Power Agency, 1, 4; - Scott Berry

Answer	
Document Name	
Comment	

The two bullets points under Requirement R1 in the current approved standard for PRC-024 should not be deleted. These should be legit reasons to trip off the unit in the “no-trip” zone.

-Generating unit(s) may trip if the protective functions (such as out-of-step functions or loss-of-field functions) operate due to an impending or actual loss of synchronism or, for asynchronous generating units, due to instability in power conversion control equipment.

-Generating unit(s) may trip if clearing a system fault necessitates disconnecting (a) generating unit(s).

For this standard to be more than just about relay setpoints or maybe inverter setpoints, entities may be forced to model their plants. This is a very expensive item and there is no guarantees that even the model will be accurate. The standard should only be about relay setpoints and if the SDT wants to add solar inverters then it needs to be very specific about what control systems and setpoints in those control systems.

Likes 0	
Dislikes 0	
Response	

Don Schmit - Nebraska Public Power District - 1,3,5

Answer	

Document Name	
Comment	
NPPD supports MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - FRCC,SERC,RF, Group Name Duke Energy	
Answer	
Document Name	
Comment	
No.	
Likes 0	
Dislikes 0	
Response	
Jeremy Voll - Basin Electric Power Cooperative - 1,3,5,6	
Answer	
Document Name	
Comment	
Support the MRO NSRF Comments	
Likes 0	
Dislikes 0	
Response	
RoLynda Shumpert - SCANA - South Carolina Electric and Gas Co. - 1,3,5,6 - SERC	
Answer	
Document Name	
Comment	

SCANA- South Carolina Electric and Gas (Dominion Energy South Carolina) is in agreement with comments form Sean Bodkin (Dominion Energy).

Likes 0	
Dislikes 0	

Response

Tom Hanzlik - SCANA - South Carolina Electric and Gas Co. - 1

Answer	
Document Name	

Comment

I agree with the comments submitted by Sean Bodkin-Dominion

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Reclamation requests clarification of the rationale in allowing the Transmission Planner to make less stringent voltage settings than those required by Attachment 2.

In the interest of developing completely clear, unambiguous, grammatically correct Requirements, R3 could be better stated as:

Each Generator Owner or Transmission Owner shall document each known regulatory or equipment limitation that prevents an applicable generating resource(s) (unit) with generator frequency or voltage protection from meeting the protection setting criteria in Requirements R1 or R2. Documentation includes (but is not limited to) study results, experience from an actual event, or manufacturer's advice.

The comment above can also be applied to R4. R4 is not very clear and may be providing an opportunity for entities to manipulate information to avoid complying. Recommend rewriting to clear up when and what processes allow for deviation from transmitting the setting information.

Likes 0	
Dislikes 0	

Response

Shirley Mathew - Austin Energy - 5	
Answer	
Document Name	
Comment	
None	
Likes 1	Austin Energy, 3, Preston W. Dwayne
Dislikes 0	
Response	
Allen Schriver - NextEra Energy - 5	
Answer	
Document Name	
Comment	
Comments: The SDT should also consider the following: • Control systems are not calibrated like protective relays, nor are they stand-alone discrete devices. • The industry has been successfully working with the manufacturers to make programming changes to resolve the issue per the NERC Alerts. • The first issue of miscalculating frequency has been resolved by the industry, and there have been no instances of reoccurrence. • Following the second alert, when inverters were tripping in the “no trip” zone, control changes were implemented for those inverters capable of being changed. • Inverter control systems sense the voltage and frequency at the inverter terminals and will initiate momentary cessation to protect the inverter. While the POI voltage may be within the PRC-024 curve, inverters can still be impacted by voltage spikes due to switching on the low side of the GSU. • The IRPTF is currently writing a Reliability Guideline: Improvements to Interconnection Requirements for BPS Connected Inverter-Based Resources (IBRs) which will detail the performance requirements per the PRC-024 curves and cover all IBRs above distribution level. Recommendations from this guideline should be taken into consideration as part of the Standard’s requirements.	
Likes 0	
Dislikes 0	
Response	
Chris Scanlon - Exelon - 1	
Answer	
Document Name	

Comment
The proposed PRC-024-3, Section 4.2.1.5 language, “Elements utilized in aggregation of the dispersed power producing resources.”, is a broad statement. The statement appears to be bringing the non-BES components of Inclusion 4, previously included as PRC-024-2 Footnote 2, into the scope of this standard. If this is the intention Exelon suggests: “Elements utilized in the aggregation of the dispersed power producing resources, as identified in BES Definition I4, from the individual BES resource to the point of aggregation, as identified in BES Definition I4. Section 4.2.1.5 as currently proposed is sufficiently broad to potentially include rooftop solar and other similar distribution systems resources. Exelon suggests the more narrow statement based on BES Definition I4 to avoid confusion. Exelon, Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment
Regarding embedded frequency protection, it is not clear if generator speed signals that result in the trip of a unit are included. TAL believes this question should be addressed in the standard given that speed is directly related to frequency.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment
The elimination of footnote 1 implies that GOs are are required to activate frequency and voltage protective relaying or protection systems where they currently may not be doing so. The footnote made it clear that the standard did not require these elements to be installed or activated on the generating unit. Additionally, the associated documents listed in section E are unnecessarily referened in the standard. The two NERC alerts resulting from the Blue Cut and Canyon fire investigations have issued many recommendations to GO's for addressing the undesired behavior of the solar powered inverter based resources. Southern Company is implementing each of the inverter parameter adjustments recommended where the hardware allows,

and believes that a national reliability standard is not necessary to accomplish the desired changes to the plant configurations to minimize the undesirable and unnecessary power production interruptions.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Thank you for the opportunity to comment.

Likes 0	
Dislikes 0	

Response

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	

Comment

Texas RE has the following additional comments:

- Texas RE requests clarification on Footnote 5 question regarding equipment limitations for wind turbines: do wind turbines equipment limitations include “smart crowbar” equipment limitations, UPS for the turbine control system, and tower vibration limits?
- Including the phrase “experience from an actual event” as allowable evidence in Measure M3 for a regulatory or equipment limitation could imply that the limitation could occur during the event. The intent of the standards is that limitations shall be documented prior to an event occurring.
- Regarding VSLs - Although the wording is clear, this reviewer is uncertain how the Severe VSL for R3 can be enforced: “…failed to document any known non-protection system equipment limitation…” There would have to be documentation to demonstrate that the entity knows about the limitation.

Likes 0	
Dislikes 0	

Response

Alyssa Hubbard - SCANA - South Carolina Electric and Gas Co. - 5	
Answer	
Document Name	
Comment	
I am in agreement with comments submitted by Sean Bodkin-Dominion.	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Allen Klassen, Westar Energy, 6, 3, 1, 5; Bryan Taggart, Westar Energy, 6, 3, 1, 5; Derek Brown, Westar Energy, 6, 3, 1, 5; Grant Wilkerson, Westar Energy, 6, 3, 1, 5; James McBee, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Jennifer Flandermeyer, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; John Carlson, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; Marcus Moor, Great Plains Energy - Kansas City Power and Light Co., 1, 3, 6, 5; - Douglas Webb, Group Name Westar-KCPL	
Answer	
Document Name	
Comment	
Comments: Kansas City Power & Light Company and Westar endorses comments submitted by EEI member companies.	
Likes 0	
Dislikes 0	
Response	
Todd Bennett - Associated Electric Cooperative, Inc. - 3, Group Name AECI	
Answer	
Document Name	
Comment	
AECI supports the comments submitted by ACES	
Likes 0	
Dislikes 0	
Response	

Sandra Shaffer - Berkshire Hathaway - PacifiCorp - 6	
Answer	
Document Name	

Comment

The NSRF has the following recommendations:

The SDT could consider the following modification to Section 4.2 to add clarity (strikethough is deleted text while italics is added text):

4.2. Facilities:

4.2.1 Frequency, voltage or volts per hertz protection *relays, software controls, firmware controls*, including frequency or voltage protective functions within control systems that provide tripping or momentary cessation signals to all or part of the generating resource, applied to the following:

4.2.1.1 Bulk Electric System (BES) generating resource(s).

4.2.1.2 BES GSU transformer(s).

4.2.1.3 High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s). *Aux transformers that are connected between the high side terminals of the generator's GSU and the BES Interconnection. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online. These transformers are variably referred to as station power, unit auxiliary*

{C}1. with more stringent voltage boundaries for the No Trip Zone. Do you agree with this proposed Quebec Variance? If not, please provide your rationale.

Yes

No

Comments: N/A for the NSRF members.

{C}2. Do you agree with the proposed Implementation Plan? If not, please provide your rationale.

Yes

No

Comments: There may be substantial retesting and replacements to comply with this proposed Standard. The NSRF recommends a 24 month implementation plan as this will give Entities planning time for maintenance outages and for budget forecasting purposes.

{C}3. Do you agree that the proposed modifications provide a cost-effective means of addressing issues in the SAR? If not, please provide an alternative, more cost-effective manner in which to achieve at least an equivalent level of reliability.

Yes

No

Comments: The NSRF believes there may be substantial cost associated with this Standard but cannot state exactly what those cost are as this is the first interaction of the proposed Standard. See question 9.

{C}4. If you have any additional comments on themes that have NOT already been addressed in the proceeding questions on this comment form, please provide them here.

Comments:

The NSRF has the following recommendations:

The SDT could consider the following modification to Section 4.2 to add clarity (strikethough is deleted text while italics is added text):

4.2. Facilities:

4.2.1 Frequency, voltage or volts per hertz protection *relays, software controls, firmware controls*, including frequency or voltage protective functions within control systems that provide tripping or momentary cessation signals to all or part of the generating resource, applied to the following:

4.2.1.1 Bulk Electric System (BES) generating resource(s).

4.2.1.2 BES GSU transformer(s).

4.2.1.3 High side of the generator-connected unit auxiliary transformer installed on BES generating resource(s). *Aux transformers that are connected between the high side terminals of the generator's GSU and the BES Interconnection. Unit auxiliary transformer(s) (UAT) that supply overall auxiliary power necessary to keep generating unit(s) online. These transformers are variably referred to as station power, unit auxiliary transformer(s) (UAT), or station service transformer(s) used to provide overall auxiliary power to the generator station when the generator is running.*

4.2.1.4 Individual d *D*ispersed power producing resources identified in the BES Definition, Inclusion I4.

4.2.1.5 Elements utilized in aggregation of the dispersed power producing resources. (Rationale comment - covered in 4.2.1.4).

4.2.1.6 Collector transformer of resources identified in the BES Definition, Inclusion I4. (Rationale comment - What transformers are these? If they are part of the <100kV collector system then they are out of scope. Per I4, there is no indication of "collector transformer(s)". If this is the GSU then it is covered in 4.2.1.2.)

Proposed requirement R4: In keeping with the intent of the current Standards Efficiency Review Project, R4 is not required within the proposed Standard as the capturing of data is redundant. The NSRF believes this can be captured under currently enforceable MOD-032-1, R2 which requests data developed by the PC and TP in R1.

Per the webinar, the SDT stated that Facilities 4.2.1.5 “Elements utilized in aggregation of the dispersed power producing resources” reads the same as PRC-025-2. The NSRF disagrees with this statement. This SDT is now expanding both PRC-025-2 and proposed PRC-024-3 to include items that make up the “collector systems”, which is directly against the FERC Approved definition of Inclusion I4. When the SDT states 4.2.1.5 is directly related to PRC-025-2 and has the same intentions, the NSRF strongly disagrees. When applying the FERC approved definition of Inclusion I4 and 4.2.1.5 of PRC-024-3 (or PRC-025-2) collector system items ARE NOT applicable to either Standard.

Likes 0	
Dislikes 0	

Response

Bette White - AES - Indianapolis Power and Light Co. - 3

Answer	
Document Name	

Comment

IPL has no other comments

Likes 0	
Dislikes 0	

Response

Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and Con Ed

Answer	
Document Name	

Comment

We congratulate the SDT on making practical improvements, like replacing POI with the high side of the main output transformers, to this standard.

The Facilities section can be consolidated. There are currently redundancies in section 4.2.1. The following Facilities can be struck:

4.2.1.2 BES GSU transformer(s). This is part of the BES Generating resource so it is captured in 4.2.1.1.

4.2.1.4. Individual dispersed power producing resources identified in the BES Definition, Inclusion I4. This is a BES generating resource so it is captured in 4.2.1.1.

4.2.1.6 Collector transformer of resources identified in the BES Definition, Inclusion I4. This is part of the BES generating resource in Inclusion I4, so for the same reasons as striking, 4.2.1.2 and 4.2.1.4., it is captured in 4.2.1.1

We suggest that the Facilities section could be simplified. We do not believe that it is necessary to include the BES applicability language within the standard, since the standard should only be applicable to the BES.

We suggest adding the NPCC Region's Frequency No Trip Boundary "Thresholds for Setting Underfrequency Trip Protection for Generators" to the Supplemental Material section of the standard. Please see PRC-006-NPCC for reference.

Likes 0	
Dislikes 0	

Response

Richard Vine - California ISO - 2

Answer	
Document Name	

Comment

The California ISO supports the comments as submitted by the ISO/RTO Council Standards Review Committee (SRC)

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

EEI member companies find the Applicability section of proposed Reliability Standard PRC-024-2 to be confusing and complex. While we appreciate SDT efforts to be thorough, we do not believe that that references to the BES definition inclusions or exclusions are needed and may even expand meaning of some parts of the BES definition. For example, Section 4.2.1.5 state that "[e]lements utilized in aggregation of the dispersed power producing resources" would be in scope, which we believe is an inappropriate expansion of the BES definition. We also do not see a need for the

inclusion of underlying facilities associated with the applicable protection systems (e.g., GSUs, generating resources, auxiliary transformers, dispersed power producing resources, and collector transformers). For this reason, we offer the following as an alternative for SDT consideration.

4. Applicability

4.1. Functional Entities

4.1.1 Generator Owners

4.1.2 Transmission Owners (*EEI disagrees with including TOs, see EEI's comments to Question 5 above*)

4.2 Exemptions

4.2.1 Plant auxiliary equipment protection systems

4.3 Facilities

4.3.1 Generator frequency protective relays (or functionally equivalent devices contained within a generating resource's control system)

4.3.2 Generator voltage protective relays (or functionally equivalent devices contained within a generating resource's control system)

Likes 0	
Dislikes 0	

Response

Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - Texas RE

Answer	
Document Name	

Comment

CenterPoint Energy Houston Electric, LLC supports the comments submitted by the Edison Electric Institute.

Likes 0	
Dislikes 0	

Response

Kagen DelRio - Kagen DelRio On Behalf of: doug white, North Carolina Electric Membership Corporation, 4, 3, 5; John Lemire, North Carolina Electric Membership Corporation, 4, 3, 5; Robert Beadle, North Carolina Electric Membership Corporation, 4, 3, 5; - Kagen DelRio

Answer	
Document Name	

Comment

NCEMC supports the comments submitted by ACES

Likes 0	
Dislikes 0	

Response

Charles Yeung - Southwest Power Pool, Inc. (RTO) - 2, Group Name SRC

Answer	
Document Name	

Comment

Evaluating Protection Settings

It is unclear whether the Evaluating Protection Settings section on page 21 of the redline proposed Standard constitutes one or more requirements in connection with the evaluation of voltage protection settings. Are these additional compliance requirements that should therefore be referred to in or made a part of the main body of the proposed Standard? Is a study being required in connection with Requirement R2? If so, the SDT should incorporate a specific requirement in the proposed standard in order to eliminate confusion and ambiguity. The specific requirement should articulate (1) Responsible Entities shall perform a study and (2) the mandatory components of the study.

Use of the term “generating resource”

The SDT should use “generator” or “generating Facility” instead of “generating resource” throughout the proposed Standard in order to conform to common usage in the standard.

Breadth of Requirement R3

We believe the equipment limitation exception to Requirements R1 and R2 that is contained in Requirement R3 is too broad and can be misapplied. As currently worded, the proposed Standard allows generating Facilities to be designed to be exempt from Requirements R1 and R2, thereby eliminating any compliance obligation to PRC-024. We suggest adding an implementation period to allow all facilities to meet the protection setting criteria.

Likes 0	
Dislikes 0	

Response

Constantin Chitescu - Ontario Power Generation Inc. - 5

Answer	
Document Name	

Comment

OPG supports RSC’s comments, and has the following additional comments:

As per PRC-024-3 requirement R1 the Eastern Interconnection Generator Owner shall set the generator frequency protections in accordance with Eastern Interconnection Boundaries (Attachment 1)

As per PRC-006-NpCC-1 Requirement R13 Each Generator Owner shall set each generator underfrequency trip relay, if so equipped, below the appropriate generator underfrequency trip protection settings threshold curve in Figure 1.

It appears that there is a gap between the compliance requirements of these two standards with respect to underfrequency protection settings that warrants SDT discrepancy review.

Likes 0	
Dislikes 0	

Response