NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project Name:	2018-04 Modifications to PRC-024-2 | PRC-024-3 (Draft 2)
Comment Period Start Date:	9/20/2019
Comment Period End Date:	11/4/2019
Associated Ballot:	2018-04 Modifications to PRC-024-2 PRC-024-3 AB 2 ST

There were 49 sets of responses, including comments from approximately 140 different people from approximately 106 companies representing 10 of the Industry Segments as shown in the table on the following pages.

All comments submitted can be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact Senior Director of Engineering and Standards Howard Gugel (via email) or at (404) 446-9693.

Questions

1. Based on industry feedback, the SDT removed the Transmission Owner (TO) from the Applicability (Functional Entities) of PRC-024-3. Do you agree with this change? If not, please provide the basis for your disagreement and a specific instance where not including the TO would present a risk to reliability.

2. Based on industry feedback, the SDT modified the Applicability (Facilities) to clarify both the types of 'protection' applicable, if activated, and the specific equipment the 'protection' is applied on. Do you agree with these changes? If not, please provide the basis for your disagreement and an alternate solution.

3. To address Scope Item 'f' from the approved SAR, the SDT added an exemption to the Applicability (Facilities) to clarify that all auxiliary equipment and associated protection(s) within the generating Facility are not applicable to the standard. Do you agree with the 'Exemption'? If not, please provide the basis for your disagreement and an alternate solution.

4. Based on industry feedback, the SDT replaced the 0.1 second 'Minimum Time (Sec)' value in the frequency tables with "Instantaneous" and provided additional clarity via Footnote #6 regarding frequency calculation/measurement. Do you agree with this change? If not, please provide the basis for your disagreement and an alternate solution.

5. Based on industry feedback, the SDT revised the Implementation Plan to provide twenty-four months for applicable entities to evaluate settings, make changes for applicable equipment, and purchase necessary equipment, if necessary. Do you agree with the revised Implementation Plan? If not, please provide the basis for your disagreement and an alternate proposal.

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

The Industry Segments are:

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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Florida Municipal Power Agency	Chris Gowder	5	FRCC	FMPA	Carol Chinn	Florida Municipal Power Agency	4	SERC
					Richard Montgomery	Florida Municipal Power Agency	6	SERC
					Michelle Johnson	Florida Municipal Power Agency	3	SERC
					Don Cuevas	Beaches Energy Services	1	SERC
					David Owens	Gainesville Regional Utilities	1	SERC
					Steven Lancaster	Beaches Energy Services	3	SERC
					Darko Kovac	Gainesville Regional Utilities	3	SERC
					Neville Bowen	Ocala Utility Services	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Nick Batty	Keys Energy Services	4	SERC
					Tom Reedy	Florida Municipal Power Pool	6	SERC
Santee Cooper	Chris Wagner	1		Santee Cooper	Rene' Free	Santee Cooper	1,3,5,6	SERC
					Debbie Schneider	Santee Cooper	1,3,5,6	SERC
					Bridget Coffman	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
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administration	1,6	MRO
					Andy Crooks	SaskPower Corporation	1	MRO
					Bryan Sherrow	Kansas City Board of Public Utilities	1	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					David Heins	Omaha Public Power District	1,3,5,6	MRO
					Jeremy Voll	Basin Electric Power Cooperative	1	MRO
					David Zwergel	Midcontinent ISO	2	MRO
					Douglas Webb	Kansas City Power & Light	1,3,5,6	MRO
					Fred Meyer	Algonquin Power Co.	1	MRO
					James Nail	Independence Power & Light (Indepdence Missouri)	1,3,5	MRO
					James Williams	Southwest Power Pool, Inc.	2	MRO
					Jamie Monette	Minnesota Power / ALLETE	1	MRO
					Jamison Cawley	Nebraska Public Power	1,3,5	MRO

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Sing Tay	Oklahoma Gas & Electric	1,3,5,6	MRO
					Terry Harbour	MidAmerican Energy	1,3	MRO
					Troy Brumfield	American Transmission Company	1	MRO
Public Utility District No. 1 of Chelan County	Davis Jelusich	6		Public Utility District No. 1 of Chelan County	Joyce Gundry	Public Utility District No. 1 of Chelan County	3	WECC
					Jeff Kimbell	Public Utility District No. 1 of Chelan County	1	WECC
					Meaghan Connell	Public Utility District No. 1 of Chelan County	5	WECC
					Davis Jelusich	Public Utility District No. 1 of Chelan County	6	WECC
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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
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
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Tara Lightner	Sunflower Electric Power Corporation	1	MRO
					Jenny Knernshield	Old Dominion Electric Cooperative	3,4	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
Duke Energy		1,3,5,6	FRCC,RF,SERC	Duke Energy	Laura Lee	Duke Energy	1	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
	Kim Thomas				Dale Goodwine	Duke Energy	5	SERC
					Greg Cecil	Duke Energy	6	RF
FirstEnergy - FirstEnergy Corporation	Mark Garza	4		FE Voter	Julie Severino	FirstEnergy - FirstEnergy Corporation	1	RF
					Aaron Ghodooshim	FirstEnergy - FirstEnergy Corporation	3	RF
					Robert Loy	FirstEnergy - FirstEnergy Solutions	5	RF
					Ann Carey	FirstEnergy - FirstEnergy Solutions	6	RF
					Mark Garza	FirstEnergy-FirstEnergy	4	RF
Southern Company - Southern Company Services, Inc.	Pamela Hunter	1,3,5,6	SERC	Southern Company	Adrianne Collins	Southern Company - Southern Company Services, Inc.	1	SERC
					Joel Dembowski	Southern Company - Alabama	3	SERC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
						Power Company		
					William D. Shultz	Southern Company Generation	5	SERC
					Ron Carlsen	Southern Company - Southern Company Generation	6	SERC
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC	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

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Helen Lainis	IESO	2	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
					Nick Kowalczyk	Orange and Rockland	1	NPCC
					Joel Charlebois	AESI - Acumen Engineered Solutions International Inc.	5	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Mike Cooke	Ontario Power Generation, Inc.	4	NPCC
					Salvatore Spagnolo	New York Power Authority	1	NPCC
					Shivaz Chopra	New York Power Authority	5	NPCC
					Mike Forte	Con Ed - Consolidated Edison	4	NPCC
					Dermot Smyth	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Ashmeet Kaur	Con Ed - Consolidated Edison	5	NPCC
					Caroline Dupuis	Hydro Quebec	1	NPCC

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Chantal Mazza	Hydro Quebec	2	NPCC
					Sean Bodkin	Dominion - Dominion Resources, Inc.	6	NPCC
					Laura McLeod	NB Power Corporation	5	NPCC
					Randy MacDonald	NB Power Corporation	2	NPCC
					Gregory Campoli	New York Independent System Operator	2	NPCC
					John Hastings	National Grid	1	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Michael Jones	National Grid USA	1	NPCC
Dominion - Dominion Resources, Inc.	Sean Bodkin	6		Dominion	Connie Lowe	Dominion - Dominion Resources, Inc.	3	NA - Not Applicable

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
					Lou Oberski	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable
					Larry Nash	Dominion - Dominion Virginia Power	1	NA - Not Applicable
					Rachel Snead	Dominion - Dominion Resources, Inc.	5	NA - Not Applicable

1. *Based on industry feedback, the SDT removed the Transmission Owner (TO) from the Applicability (Functional Entities) of PRC-024-3. Do you agree with this change? If not, please provide the basis for your disagreement and a specific instance where not including the TO would present a risk to reliability*.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
How does it make sense that GSUs owned by GOs are in scope, but GSUs owned by TOs are not? Are GSUs owned by TOs less of a risk to the BES?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT reached out to industry in attempt to quantify the risk of not requiring PRC-024 protection setting requirements on GSUs owned by entities registered as TOs. Other than in the Quebec Interconnect, no instances were identified where a GSU was owned by an entity registered as a TO and not also registered as a GO. As such, the SDT determined that there would be no reliability risk by continuing to exclude TOs from the Applicability (except for Quebec) and therefore, to include TOs as an Applicable Functional Entity would add unnecessary compliance burden on TOs to document their non-ownership of GSUs.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	

Some Transmission Owners (TO) apply voltage and frequency trip settings at the Point of Interconnection that trip generation based on PRC-024 voltage and frequency requirements, particularly for inverter-based resources tapped onto network transmission lines. These TO's typically have the same functionality applied by the Generator Owner (GO). This arrangement would suggest that both the GO and TO should comply with PRC-024. If the TO is not required to comply with PRC-024, it could trip a generating plant quicker than required by PRC-024.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Inclusion of voltage and frequency relays applied on transmission lines is outside of the PRC-024-3 SAR and the PRC-024-3 Supplemental SAR.	
Rachel Coyne - Texas Reliability Entity, Inc. – 10	
Answer	No
Document Name	
Comment	
Although it is uncommon for the TO to own the generator step-up (GSU) or main power transformer (MPT), in cases where to TO does own the GSU or MPT the TO should be required to take steps to ensure the generator rides through voltage and frequency excursions as prescribed within the Standard.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT reached out to industry in attempt to quantify the risk of not requiring PRC-024 protection setting requirements on GSUs owned by entities registered as TOs. Other than in the Quebec Interconnect, no instances were identified where a GSU was owned by an entity registered as a TO and not also registered as a GO. As such, the SDT determined that there would be no	

reliability risk by continuing to exclude TOs from the Applicability (except for Quebec) and therefore, to include TOs as an Applicable Functional Entity would add unnecessary compliance burden on TOs to document their non-ownership of GSUs.	
Marty Hostler - Northern California Power Agency – 5	
Answer	No
Document Name	
Comment	
Why are TO's GSU protection not included but GO's GSUs are? Also see DUKE, and TRE.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT reached out to industry in attempt to quantify the risk of not requiring PRC-024 protection setting requirements on GSUs owned by entities registered as TOs. Other than in the Quebec Interconnect, no instances were identified where a GSU was owned by an entity registered as a TO and not also registered as a GO. As such, the SDT determined that there would be no reliability risk by continuing to exclude TOs from the Applicability (except for Quebec) and therefore, to include TOs as an Applicable Functional Entity would add unnecessary compliance burden on TOs to document their non-ownership of GSUs.	
Michelle Amarantos - APS - Arizona Public Service Co. – 1	
Answer	Yes
Document Name	
Comment	
AZPS appreciates that this was changed.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
The NSRF has concerns with the term “main power transformer (MPT)”. This term is not included in the NERC Glossary of Terms, nor is it well defined in this proposed revision to PRC-024-3. It is introduced as a part of the inclusion of the TO Functional Entity requirement limited to the Quebec Interconnection, yet it is included in the text of Requirement 2 as well as Attachment 2, applicable to the Eastern, Western, and ERCOT Interconnections in the United States. The NSRF requests that the inclusion of this new term in this Standard be reversed, or a formal definition of the term be provided in the Standard or NERC Glossary of Terms.	
Likes 1	Alliant Energy Corporation Services, Inc., 4, Heckert Larry
Dislikes 0	
Response	
Thank you for your comment. The drafting team believes that the term “main power transformer (MPT)” is used broadly throughout the dispersed generation industry. The SDT has added a footnote to more clearly establish its intent in the use of the term “main power transformer (MPT).”	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
BHC agrees with EEI’s comments as submitted	
Likes 0	

Dislikes 0	
Response	
Please see response to EEI.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BPA is supportive of the proposed change. BPA would like to point out for consideration that this change could possibly be creating a loophole under the following scenario. *If a Generator Owner installs a GSU on a new project that does not meet the requirements outlined in the standard, they could potentially decide with a Transmission Owner, to make the ownership change on the low side, essentially giving the GSU to a non-Quebec Transmission Owner.* *If this scenario played out, would the non-Quebec Transmission Owner not need to consider the protection of that GSU for this standard?* Perhaps this is a far-fetched scenario but it was a thought that came to mind regarding this change. The BPA subject matter experts that reviewed this standard do not see this hypothetical loophole as a measurable risk to reliability that would justify a disagreement with the change. BPA only wants to share the thought for others to consider.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	

Comment	
agree with EEI Comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	
There is concern for addressing frequency protection settings for interties on transmission lines. Because PRC-024 applies to generating resources, should this concern be addressed in PRC-024 or in a separate Standard?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Inclusion of voltage and frequency relays applied on transmission lines is outside of the PRC-024-3 SAR and the PRC-024-3 Supplemental SAR.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

EEI supports the removal of Transmission Owners (TOs) from the Applicability Section of this Reliability Standard believing that this change is consistent with the purpose of the standard and how TOs operate throughout the US.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
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	
Westar Energy and Kansas City Power & Light support the Edison Electric Institutes (EEI) Comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes

Document Name	
Comment	
Support the MRO NSRF Comments, as follows: The NSRF has concerns with the term “main power transformer (MPT)”. This term is not included in the NERC Glossary of Terms, nor is it well defined in this proposed revision to PRC-024-3. It is introduced as a part of the inclusion of the TO Functional Entity requirement limited to the Quebec Interconnection, yet it is included in the text of Requirement 2 as well as Attachment 2, applicable to the Eastern, Western, and ERCOT Interconnections in the United States. The NSRF requests that the inclusion of this new term in this Standard be reversed, or a formal definition of the term be provided in the Standard or NERC Glossary of Terms.	
Likes 0	
Dislikes 0	
Response	
Please see response to the MRO NSRF.	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC	
Answer	Yes
Document Name	PRC-024-3 HQ comments.docx
Comment	
Hydro-Quebec supports the comments submitted by the RSC. In addition, Hydro-Quebec has the following comments : · Review and clarify footnote #4 associated with Requirement #3. The last part that was added regarding the protection imbedded in control systems for IBRs brings some confusion as it relates to the protection system itself while the first part of the sentence relates to the equipment that is protected: “Excludes limitations caused by the setting capability of the frequency and voltage protective relays for	

the generating resource(s) but does not exclude limitations originating in the equipment protected by the relays or frequency and voltage protection embedded in control systems." · In Attachment 1, we recommend adding the distinct over frequency requirement (curve) that currently applies to thermal generation and IBRs in the Quebec Interconnection . Please see attached file.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. See the Q4 response for RSC comments. The SDT has made changes to new footnote #6 to address this concern. Regarding Attachment 1 comment, this is not currently in the scope of Project 2018-04.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon supports the SDTs decision to limit applicability to functional entities that apply the protection systems that are the subject of the standard. On behalf of Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
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	
Bette White - AES - Indianapolis Power and Light Co. - 3	
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	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Carrie Dixon, Xcel Energy, Inc. , 6; Gerry Huitt, Xcel Energy, Inc., 1, 5, 3; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Donald Lynd - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
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	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Siddharth Pant - GE - General Electric Power Systems - NA - Not Applicable - NA - Not Applicable	
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	
Nick Batty - Keys Energy Services - 9 - SERC	
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 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - WECC	
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	
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	
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	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 5, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Trevor Tidwell - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Line Dufour - Hydro-Qu?bec Production - 6 - NPCC	
Answer	
Document Name	
Comment	
N/A, For Quebec interconnection, TO is still part of the standards	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	

2. ***Based on industry feedback, the SDT modified the Applicability (Facilities) to clarify both the types of 'protection' applicable, if activated, and the specific equipment the 'protection' is applied on. Do you agree with these changes? If not, please provide the basis for your disagreement and an alternate solution*****.**

Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	No
Document Name	

Comment	
Paragraph 4.2.1.5 includes items not included in the BES definition document and should not be included in the scope of PRC-024. Paragraph 4.2.1.4 should be the limit of the scope of equipment covered by PRC-024 for inverter-based resources.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the SDT believes that this is not a change from PRC-024-2.	
Chris Gowder - Florida Municipal Power Agency - 5, Group Name FMPA	
Answer	No
Document Name	
Comment	
1. Main Power Transformer (MPT)- not defined anywhere. The intent was to replace "collector transformer", but MPT is no better without context. Also, the term is defined in the Quebec-only language, then used in NERC-wide language. 2. Footnote seems to be adding unneccessary complexity. 3. Use of term capacity in the facility definition will lead to confusion, should just refer to BES definition Inclusion I4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. 1. The drafting team believes that the term "main power transformer (MPT)" is used broadly throughout the dispersed generation industry. The SDT has added a footnote to more clearly establish its intent in the use of the term "main power transformer (MPT)." 2. The SDT is unsure which footnote is being referred to but believes that all footnotes are needed. 3. The wording in 4.2.1.4 – 4.2.1.6 is intended to clarify what equipment is included and was previously described in PRC-024-2 footnote 4.	

Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	No
Document Name	
Comment	

The terms “cease injecting current”, “cease current injection” and “momentary cessation” are not defined, nor commonly understood.

Significant reduction of the amount of current being injected has a similar effect to momentary current cessation; they both deprive the grid of much needed support during the disturbance which negatively impacts grid reliability, and therefore, should not be an option, nor allowed without approval.

Understanding the compounded effect on the grid of a multitude of inverters having similar design is important and accurate modelling may not be possible without adequate information regarding the amount of current being reduced.

OPG recommends the terms “cease injecting current”, “cease current injection” and “momentary cessation”, used throughout the standard (applicable Facilities 4.2.1, R1, R2, applicable protection definition per footnote 3, D.A.2, Attachment 2a, etc.), to be replaced with “ceasing injecting current or significant reduction in current injection”.

If this comment is adopted and implemented as such then there is a need to define the term “significant”.

Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	

See AEP, Duke, andTRE comments.	
Likes 0	
Dislikes 0	
Response	
Please see response to AEP, Duke and TRE comments.	
Armin Klusman - CenterPoint Energy Houston Electric, LLC - 1 - WECC	
Answer	No
Document Name	
Comment	
CenterPoint Energy Houston Electric, LLC (CenterPoint Energy) disagrees with changing “collector transformer” to a newly developed term of “main power transformer (MPT)”. The use of “power” in the term tends to suggest a distribution substation power transformer instead of a transformer at a generation resource substation. A more applicable term would be ‘main step-up (MSU) transformer’. Other possible terms that could be considered are ‘main transformer (MT)’ or ‘station step-up (SSU) transformer’ which is used in the current draft of the Compliance Implementation Guidance PRC-019-2 that is being developed by a NERC Planning Committee task force. The term ‘main transformer’ is used in several places in the recently approved NERC Reliability Guideline – Improvements to Interconnection Requirements for BPS-Connected Inverter-Based Resources (September 2019). Regardless of what the collector transformer is renamed, CenterPoint Energy recommends adding a second figure in Attachment 2 (voltage ride-through) with a station sketch to provide clarity on Footnote 8: “Voltage at the high-side of the GSU or MPT.”	
Likes 0	
Dislikes 0	
Response	

Thank you for your comment. The drafting team believes that the term “main power transformer (MPT)” is used broadly throughout the dispersed generation industry. The SDT has added a footnote to more clearly establish its intent in the use of the term “main power transformer (MPT).”	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
Applicable Facilities only address protection up to the GSU or MPT. However, Texas RE has noted voltage protection applied on lines interconnecting a generating Facility to a Transmission station where the line protection is set to trip within the “no-trip zone” of PRC-024-2 Attachment 2. Texas RE recommends the SDT not limit the Facilities that are applicable to the Standard and should include any voltage or frequency protection that would result in an inability of the generating resource to ride through a frequency or voltage excursion as prescribed in Attachment 1 and Attachment 2.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Inclusion of voltage and frequency relays applied on transmission lines is outside of the PRC-024-3 SAR and the PRC-024-3 Supplemental SAR.	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	No
Document Name	
Comment	
SRP supports most of the changes to the Applicability section. However SRP requests the SDT clarify 4.2.1, specifically "functions within the associated control systems". The phrase may be interpreted to include exciter settings even though they are covered by PRC-019-2.	

Likes 0	
Dislikes 0	
Response	
Thank you for your comment, the SDT believes voltage and frequency setting in excitation systems were previously included in PRC-024-2 footnote 1. For clarity this information has been moved to Facilities paragraph 4.2.1 in PRC-024-3.	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	No
Document Name	
Comment	
Given Duke Energy's response to Question #1, PRC-024 should apply to equipment out to the Point of Interconnection.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Inclusion of voltage and frequency relays applied on transmission lines is outside of the PRC-024-3 SAR and the PRC-024-3 Supplemental SAR.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	
The changes proposed to 4.2.1.5, specifically in regards to the text "to the point where those resources aggregate to greater than 75 MVA" may not be reflective of all real-world conditions given that the currently proposed scope has been pared back to the Generator Owner.	

Referencing a subset of the BES in the Facilities section seems to be a somewhat unorthodox approach in establishing the Facilities within scope.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The wording in 4.2.1.4 – 4.2.1.6 is intended to clarify what equipment is included and was previously described in PRC-024-2 footnote 4.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Microprocessor technology allows for protection elements to be embedded in a broad variety of control systems. Exelon agrees with the changes made to clarify applicability of the standard to all elements providing protection that is the subject of this standard. Note that volts per hertz relays are identified within the Applicability Section, however Footnote 4 does not specifically reference volts per hertz relay. For consistency Exelon requests that Volts Per Hertz relays are included in Footnote 4. On behalf of Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT has made this change in the new footnote 6.	
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	
Westar Energy and Kansas City Power & Light support the Edison Electric Institutes (EEI) Comments.	
Likes 0	
Dislikes 0	
Response	
See response to EEI's comment.	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
EEI supports the changes made to the Applicability (Facilities) section of PRC-024-3 (Draft 2) believing it accurately reflects those facilities within the US that should be covered under this Reliability Standard. However, one area that the SDT should investigate further is the proposed change from "collector transformer" to "main power transformer (MPT)". This type of transformers is referenced using at least three different names in three different documents. (i.e., collector transformer – BES Definition; MPT – PRC-024-3 Draft 3 and SSU (Station Step-up) within Implementation Guidance (*Under development by the SPCS*) for PRC-019, pages 71 -73). EEI suggest that NERC and the various SDTs and committees agree on a single name, that is defined, in order to ensure consistency and avoid confusion. EEI also notes that volts per hertz relays are specifically identified within the Applicability Section (4.2.1), however, in Footnote 4 these relays are not specifically identified. For consistency, EEI suggests making the following change to Footnote 4: (*indicated in bold below*)	

Footnote 4: Excludes limitations caused by the setting capability of the frequency**, and** voltage **and volts per hertz** protective relays for the generating resource(s) but does not exclude limitations originating in the equipment that the relays protect or frequency and voltage protection imbedded in control systems.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The drafting team believes that the term “main power transformer (MPT)” is used broadly throughout the dispersed generation industry. The SDT has added a footnote to more clearly establish its intent in the use of the term “main power transformer (MPT).” The SDT has made this change in the new footnote 6.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	

Comment	
BHC agrees with EEI's comments as submitted	
Likes 0	
Dislikes 0	
Response	
See response to EEI.	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Trevor Tidwell - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Line Dufour - Hydro-Qu?bec Production - 6 - NPCC	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
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	

Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
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	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
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 0	
Dislikes 0	
Response	

Nick Batty - Keys Energy Services - 9 - SERC	
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	
Michael Goggin - Grid Strategies - 5 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Siddharth Pant - GE - General Electric Power Systems - NA - Not Applicable - NA - Not Applicable	
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	
Glen Farmer - Avista - Avista Corporation - 5	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lynd - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Carrie Dixon, Xcel Energy, Inc. , 6; Gerry Huitt, Xcel Energy, Inc., 1, 5, 3; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
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	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
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	

Bette White - AES - Indianapolis Power and Light Co. - 3	
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	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
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	

3. *To address Scope Item 'f' from the approved SAR, the SDT added an exemption to the Applicability (Facilities) to clarify that all auxiliary equipment and associated protection(s) within the generating Facility are not applicable to the standard. Do you agree with the 'Exemption'? If not, please provide the basis for your disagreement and an alternate solution*.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	
The language in section 4.2.1.3 appears to conflict with the language in section 4.2.2. Section 4.2.3.1 includes the high side of the generator-connected auxiliary transformer, while section 4.2.2 exempts protection on all auxiliary equipment within the generating Facility. Please clarify why Facilities meeting applicability Section 4.2.1.3 would not fall under this exemption. Texas RE has the following additional comments: • The Severe VSL for R4 needs an additional row space between settings and "OR". • Page 9 of 23 states: "In Requirements R1, R3, and R4, all references to "Generator Owner" are replaced with "Generator Owner ***and*** Transmission Owner."" Texas RE noticed on Page 12 of 23: VSL for D.A.2. says Generator owner "**or**" Transmission Owner. Should it be changed to "**and**" to be consistent with the statement above?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Section 4.2.1.3 specifically refers to protection connected to the high side of the UAT. Auxiliary equipment typically is connected on the low side of the UAT.	

The space has been added in the severe VSL for R4. These comments pertain to the Hydro Quebec variance. In that system, there are cases where the main power transformer is not owned by the interconnecting utility. Thus is it possible that a violation could be committed by either the Generator Owner OR the Transmission Owner.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
See TRE comments.	
Likes 0	
Dislikes 0	
Response	
See response to TRE.	
Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Volts/Hertz relaying is specifically included in the applicability section 4.2.1., but is not included in the exemptions listed in Footnote 4. Please include the relay function Volts/Hertz as part of Footnote 4.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. The SDT has made this change in the new footnote 6.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
BHC agrees with EEI's comments as submitted	
Likes 0	
Dislikes 0	
Response	
See response for EEI's comment.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	

Answer	Yes
Document Name	
Comment	
Support NSRF Comments: Volts/Hertz relaying is specifically included in the applicability section 4.2.1., but is not included in the exemptions listed in Footnote 4. Please include the relay function Volts/Hertz as part of Footnote 4.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT has made this change in the new footnote 6.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Exelon appreciates and supports the clearly stated exemption for auxiliary equipment. On behalf of Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	

Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
Please see the response to MRO NSRF.	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
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	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
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	

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	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	

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	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Carrie Dixon, Xcel Energy, Inc. , 6; Gerry Huitt, Xcel Energy, Inc., 1, 5, 3; - Amy Casuscelli	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lynd - CMS Energy - Consumers Energy Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Glen Farmer - Avista - Avista Corporation - 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	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Siddharth Pant - GE - General Electric Power Systems - NA - Not Applicable - NA - Not Applicable	
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	

Nick Batty - Keys Energy Services - 9 - SERC	
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 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 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	
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	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
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	
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	
Line Dufour - Hydro-Qu?bec Production - 6 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC	
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	
Chris Gowder - Florida Municipal Power Agency - 5, Group Name FMPA	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Trevor Tidwell - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

4. Based on industry feedback, the SDT replaced the 0.1 second 'Minimum Time (Sec)' value in the frequency tables with "Instantaneous" and provided additional clarity via Footnote #6 regarding frequency calculation/measurement. Do you agree with this change? If not, please provide the basis for your disagreement and an alternate solution.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
It appears it was changed back to what is was originally? We need a Redline showing changes form the last approved standard to the current proposal.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. A redline to last approved will be posted with final ballot.	
Jamie Monette - Allete - Minnesota Power, Inc. - 1	
Answer	No
Document Name	
Comment	
Minnesota Power suggests changing the frequency tables and figures to show "Time Delay" rather than "Time." Then the tables could show 0.0 seconds, or they could go back to what was shown in PRC-024-2 "Instantaneous Trip." Minnesota Power suggests altering Footnote 7 to read:	

"Frequency is calculated over a window of time. Time delays shown in Attachment 1 Figures 1-4 and Tables 1-4 refer to the minimum required time delay after the frequency calculation has completed." The last sentence of the current footnote is confusing ("Instantaneous trip settings based on instantaneously calculated frequency measurement is note permissible."). If this sentence remains, the standard should clarify the minimum window required rather than just describing a typical window.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT believes the frequency tables and figures are appropriately labeled. The SDT believes the existing footnote adequately addresses the issue of frequency measurement.	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Support the MRO NSRF comments.	
Likes 0	
Dislikes 0	
Response	
See response to MRO NSRF.	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	

Comment
Exelon agrees with the change back to “Instantaneous”, however Footnote #7 describes a concern associated with microprocessor protection only and should therefore be limited to microprocessor protection. Exelon suggests the following language: 7 Microprocessor protection calculates frequency over a window of time. While the frequency boundaries include the option to trip instantaneously for frequencies outside the specified range, microprocessor protection should perform this calculation over a time window. Typical window/filtering lengths are three to six cycles (50 – 100 milliseconds). Instantaneous trip settings by microprocessor protection based on instantaneously calculated frequency measurement is not permissible. Electromechanical and solid-state protection does not exhibit the concern described and may use instantaneous trip settings. On behalf of Exelon, Segments 1, 3, 5, 6

Likes 0	
Dislikes 0	

Response
Thank you for your comment. The SDT believes the existing footnote adequately addresses the issue of frequency measurement. If electromechanical and solid-state protection do not exhibit the concern and do not calculate frequency instantaneously, then they would not be subject to the footnote. The footnote will remain technology-neutral.

Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	

Comment
Support NSRF comments:

Footnote 7 states that instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible. We request an explanation of the technical basis of this footnote and methods to determine whether our trip settings are permissible. It seems that verification will be difficult to achieve without input from relay manufacturers.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. A finding from Blue Cut Fire Event states, "A significant amount of solar PV resources disconnected due to a perceived system frequency below 57 Hz. This perceived frequency was due to the PLL indicating a near instantaneous frequency during the transient/distorted waveform period as less than 57 Hz."	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Please include the NPCC Region's underfrequency no-trip boundary in the Supplemental Material section of the standard – Attachment 1. The NPCC Region's under-frequency boundary is more stringent than the Eastern Interconnection Boundary. The low voltage duration, voltage (pu) < 0.45 minimum (sec) 0.15 appears to be insufficient. Clearing times for High Voltage circuits can often exceed 0.15 seconds. Therefore, the exposure to generators tripping during normally cleared faults is higher than optimal. Please consider increasing the Low Voltage Duration No Trip Zone-boundary for the <0.45 pu voltage threshold. Please consider adding additional details of restrictions on active and reactive power cessations during underfrequency or overfrequency conditions. As written, the standard could allow momentary cessation of active (real) current inside the frequency envelope of Attachment 1, as long as reactive current is provided. Cessation of active (real) current for frequencies inside the frequency envelope could compromise the effectiveness of the UFLS program.	
Likes 0	
Dislikes 0	

Response	
Thank you for your comment. Inclusion of the NPCC Region's underfrequency no-trip boundary is not part of Project 2018-04 scope. The team does not have enough technical justification to change the trip curves from the original version and it is not included in Project 2018-04 scope. The current draft is written intentionally to allow for a cease of real or reactive current, but not both simultaneously.	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Shouldn't the graph also reflect this change with the minimum time changed to 0 second?	
Likes 0	
Dislikes 0	
Response	
Per footnote 6: "The figures do not visually represent the "no trip zone" boundaries before 0.1 seconds and after 10,000 seconds. The Frequency Boundary Data Points Table defines the entirety of the "no trip zone" boundaries". This is due to the limitations of plotting a figure on a logarithmic scale.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Texas RE noticed this shows as Footnote 7, not Footnote 6.	
Likes 0	

Dislikes 0	
Response	
Thank you for your comment. This was a typo in the question.	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
BHC agrees with EEI's comments as submitted	
Likes 0	
Dislikes 0	
Response	
See response to EEI comments.	

Dana Klem - MRO - 1,2,3,4,5,6 - MRO, Group Name MRO NSRF	
Answer	Yes
Document Name	
Comment	
Footnote 7 states that instantaneous trip settings based on instantaneously calculated frequency measurement is not permissible. We request an explanation of the technical basis of this footnote and methods to determine whether our trip settings are permissible. It seems that verification will be difficult to achieve without input from relay manufacturers. The note, "The area outside the "No Trip Zone" is not a "Must Trip Zone" is not included after the graph on PRC-024 – Attachment 2, Page 21/27 of the redline draft 09202019.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. A finding from Blue Cut Fire Event states: "A significant amount of solar PV resources disconnected due to a perceived system frequency below 57 Hz. This perceived frequency was due to the PLL indicating a near instantaneous frequency during the transient/distorted waveform period as less than 57 Hz." For relay's the relay manufacture documentation may provide this verification. The note, "The area outside the "No Trip Zone" is not a "Must Trip Zone" will be included on the final draft after the graph on PRC-024 – Attachment 2.	
Leonard Kula - Independent Electricity System Operator - 2	
Answer	Yes
Document Name	
Comment	

In order to prevent the facility from being tripped for phase to ground faults cleared in breaker failure time, we suggest that the wording "Unless otherwise specified by the Transmission Planner" be added to the Boundary Details #4 in Attachment 2: Voltage Boundary Clarifications – Eastern, Western, and ERCOT Interconnections, as follows: ***" 4. Unless otherwise specified by the Transmission Planner, voltages in boundaries assume RMS fundamental frequency phase-to-phase ground or phase-to-phase unit per unit voltage."***	
Likes 0	
Dislikes 0	
Response	
Thank you for the comments, but it's not clear to the SDT what other voltage boundaries the Transmission Planner would specify.	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Trevor Tidwell - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Chris Gowder - Florida Municipal Power Agency - 5, Group Name FMPA	
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	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Line Dufour - Hydro-Qu?bec Production - 6 - NPCC	
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	
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	
Mark Gray - Edison Electric Institute - NA - Not Applicable - NA - Not Applicable	
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	
Glenn Barry - Los Angeles Department of Water and Power - 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 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 9 - SERC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Goggin - Grid Strategies - 5 - NA - Not Applicable	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Siddharth Pant - GE - General Electric Power Systems - NA - Not Applicable - NA - Not Applicable	
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	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lynd - CMS Energy - Consumers Energy Company - 1	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Carrie Dixon, Xcel Energy, Inc. , 6; Gerry Huitt, Xcel Energy, Inc., 1, 5, 3; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
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	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
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	
Bette White - AES - Indianapolis Power and Light Co. - 3	
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	

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

5. *Based on industry feedback, the SDT revised the Implementation Plan to provide twenty-four months for applicable entities to evaluate settings, make changes for applicable equipment, and purchase necessary equipment, if necessary. Do you agree with the revised Implementation Plan? If not, please provide the basis for your disagreement and an alternate proposal*.

Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

As we similarly stated in the previous comment period, we believe that 24 months is still 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.

There are a number of important, non-controversial clarifications being proposed to improve this standard that should not be delayed by the perhaps more controversial and possibly even more time-consuming requirements. For example, the proposed clarifications for Attachments 1 and 2 could and should be implemented as soon as practical, however any revisions affecting the applicability scope or “point of interconnection” should be delayed in their implementation. As a result, we suggest splitting implementation to advance as rapidly as possible these clarifications.

Likes 0	
Dislikes 0	
Response	

Thank you for your comments. The SDT continues to believe 24 months for implementation is sufficient, and the currently enforceable standard also uses the high-side as the point of interconnection. Also, the team believes that assessing any voltage, volts per hz, and frequency applied on the high-side of the UAT should not be burden within the 24 month timeframe.	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC	
Answer	No
Document Name	
Comment	
As discussed in some detail in the previous round of comments, the 24-month implementation period (though better than the original 18-month one) is still not enough time for some (nuclear, in particular) units to implement the new requirements if they have equipment that has to be modified. Per the typical nuclear projects process, they have to 1) obtain funding for and perform an analysis to see if they have compliance gaps [this can take a year plus, depending on when this version gets approved and where they are in the annual funding cycle] and, if so, 2) obtain funding for the change(s) [possibly another year plus], 3) instigate and award a contract to a design partner to complete the design for the change(s) [9 months to a year], and 4) implement the changes which will likely require an outage that can be as much as two years in the future [the change(s) likely won't be that hard to do, but the projects process requires that designs be complete at least 13 months prior to the beginning of the outage, which adds another year plus]. All together, these timeframes could easily add up to well over four years. The original dates for version 1 (and 2) were phased in over a 5-year period. This same issue was raised for the implementation of PRC-025-2 and its SDT provided 5-years to implement the requirements for any new scope. Please provide a 5-year implementation period to give time to implement any required modifications within the standard projects process.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT continues to believe the 24-month implementation is sufficient. Any potential changes based on the revised standard will probably be limited to set point changes.	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
Answer	No

Document Name	
Comment	
Consider a 60-month phased implementation plan as setting changes require time to account for planning, budgeting and outage coordination.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT continues to believe the 24-month implementation is sufficient. Any potential changes based on the revised standard will probably be limited to set point changes.	
Karie Barczak - DTE Energy - Detroit Edison Company - 3, Group Name DTE Energy - DTE Electric	
Answer	No
Document Name	
Comment	
24 months is not sufficient for nuclear power plants. Please reconsider a 36 or 48 month implementation plan.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. The SDT continues to believe the 24-month implementation is sufficient. Any potential changes based on the revised standard will probably be limited to set point changes.	
Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	

Comment
NERC originally provided a five year progressive implementation plan for PRC-024-1 and -2. PRC-023-3's original SAR was for Inverter based resources, then a supplemental SAR was developed include UAT and GSUs protection. All PRC-024 studies now have to be redone and potentially more modifications/additions made. The implementation plan should be 5-years.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The SDT continues to believe the 24-month implementation is sufficient. Any potential changes based on the revised standard will probably be limited to set point changes.

Daniel Gacek - Exelon - 1

Answer	No
Document Name	

Comment
As discussed in some detail in the previous round of comments, the 24-month implementation period (though better than the original 18-month one) is still not enough time for existing, non-inverter based generating units to perform studies, assess compliance with the new revision to the Standard, and implement any necessary modification Nuclear units typically operate continuously and therefore modifications are scheduled during refueling outages. Refueling outages take place approximately every two years and the work is scheduled years in advance. From budgeting to execution, the modification process at a nuclear unit can add up to well over four years. This concern was also communicated to the NERC SDT for PRC-025-2 resulting a 5-year implementation period for scope changes. The original dates for PRC-024 version 1 (and 2) were phased in over a 5-year period. Please consider the same 5-year implementation period for existing, non-inverter based generating units to perform studies and implement any required modifications within their established projects timeframe.

On behalf of Exelon, Segments 1, 3, 5, 6	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT continues to believe the 24-month implementation is sufficient. Any potential changes based on the revised standard will probably be limited to set point changes.	
Anthony Jablonski - ReliabilityFirst - 10	
Answer	Yes
Document Name	
Comment	
ReliabilityFirst notes that there is currently an ERO-endorsed guidance on PRC-024-2. Can ReliabilityFirst assume this ERO-endorsed guidance will be updated as well whenever PRC-024-3 is approved?	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Any of the pre-authorized entities can submit revised Implementation Guidance.	
Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - MRO,WECC	
Answer	Yes
Document Name	
Comment	
BHC agrees with EEI's comments as submitted	

Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	
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	

Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
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	
Bette White - AES - Indianapolis Power and Light Co. - 3	
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	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bridget Silvia - Sempra - San Diego Gas and Electric - 3	

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	
Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Amy Casuscelli On Behalf of: Carrie Dixon, Xcel Energy, Inc. , 6; Gerry Huitt, Xcel Energy, Inc., 1, 5, 3; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Donald Lynd - CMS Energy - Consumers Energy Company - 1	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 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	
Richard Jackson - U.S. Bureau of Reclamation - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Siddharth Pant - GE - General Electric Power Systems - NA - Not Applicable - NA - Not Applicable	
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	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Nick Batty - Keys Energy Services - 9 - SERC	
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 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Glenn Barry - Los Angeles Department of Water and Power - 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	
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	
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	
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	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Line Dufour - Hydro-Qu?bec Production - 6 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC	
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	
Chris Gowder - Florida Municipal Power Agency - 5, Group Name FMPA	
Answer	Yes
Document Name	

Comment	
Likes 0	
Dislikes 0	
Response	
Trevor Tidwell - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

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

Marty Hostler - Northern California Power Agency - 5	
Answer	No
Document Name	
Comment	
More studies and work have to be done. We really need a Standards process that is standard and thoughtfully implemented. It appears Standard modifications are coming out to quickly and causing inefficiencies in redoing work already done. (Standards efficiency project topic?) NERC should provide a redline showing the difference between the new proposed standard and the existing standard first. NERC should provide a list detailing studies GO's already did, versus what needs to be redone to comply with the proposed standard. AND provide an honest cost estimate of redoing studies.	
Likes 0	
Dislikes 0	
Response	
Thank you for your feedback. While this is outside of the standard drafting team's scope of duties, NERC staff will share this concern with NERC standards leadership and staff leading the Standards Efficiency Review team. A redline to last approved will be posted with final ballot. To comply with the new PRC-024-3, the SDT believes that there is not a significant amount of rework of studies required. The SDT believes as few changes to the standard as needed were made while filling reliability gaps.	

Sean Bodkin - Dominion - Dominion Resources, Inc. - 6, Group Name Dominion	
Answer	No
Document Name	
Comment	
Since the comment form does not provide for 'other' or 'additional' comments related to the proposed PRC-024 changes, Dominion Energy is submitting the following comments under this section: 1) Additional clarity around whether the boundary for voltage ride through is part of the no-trip zone or not. This is unclear on the curves and different Regions have interpreted this differently. 2) The revised standard and guidance documents do not address issues, specifically the reflection process, outlined in the NERC Inverter Based Resource Performance Guide that blurs 1.0 per unit inverter voltage (based on inverter rated voltage) and 2) POI voltage in per unit, and appears to equate them. If this is the intenet then it should be clearly stated in the revised standard or associate guidance documents. Dominion Energy recommends it be clearly stated that in lieu of reflection voltage, GOs should be allowed to use inverter rated voltage as being equivalent to POI voltage; or allow inverter skid settings to ride the line due to the fact that simulation results illustrate inverter schemes are completely restrained for system POI voltages along the LVRT boundary in PRC-024 Attachment 2.	
Likes 1	Northern California Power Agency, 5, Hostler Marty
Dislikes 0	
Response	
Thank you for your comment. The SDT believes the table “Voltage Boundary Data Points” in Attachment 2 indicate if the lines are inclusive or not in the graph. The SDT believes that the “Evaluate Protection Settings” Section clearly indicates the voltage values in the Attachment 2 voltage boundaries are voltages at the high side of the GSU/MPT. When evaluating protection settings, consider the voltage differences between where the protection is measuring voltage and the high side of the GSU/MPT.	
Rachel Coyne - Texas Reliability Entity, Inc. - 10	
Answer	No
Document Name	
Comment	

Texas RE does not have comments on this question.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Siddharth Pant - GE - General Electric Power Systems - NA - Not Applicable - NA - Not Applicable	
Answer	No
Document Name	
Comment	

All the items below can be addressed by clarifications or corrections. They are a possible cause for confusion as stated in the current draft.

ITEM 1:

PRC-024-2 note 3 in Attachment 2 clarified that the times in the voltage/time curves were cumulative. The SAR had asked for clarifications with respect to start/stop/reset times while leaving cumulative in the verbiage. With the removal of "cumulative" from the voltage/time curves in the draft, there is room for mis-interpretation of the requirements, unless some interpretation guidance is also included. Is it a voltage vs. time profile as given in other grid codes? In other words, does it represent the "worst case" voltage as would be observed on an oscilloscope? Or, should it be interpreted some other way?

As an example, for an rms voltage with the following profile (very extreme, but just to make a point):

a. t<0, V=1

b. 0 <= t < 0.1 sec, V = 0

c. 0.1 sec <= t < 1 sec, V=1

d. 1 sec <= t < 1.06 sec, V = 0

e. 1.06 sec <= t <=4 sec, V = 1

With "cumulative" in the description, the above curve would be interpreted as falling outside of the "No Trip Zone" of PRC-024-2 as the total time when the voltage is below 0.45 pu is 0.16 sec. What would be the interpretation in the draft PRC-024?

To carry this to an even more extreme, if the voltage was essentially toggling between 1 and 0 every 0.1 sec, that would clearly be outside the "No Trip Zone" of PRC-024-2. How should it be interpreted in the current draft?

ITEM 2:

Attachment 2 - The voltage ride-through figure includes ERCOT in the caption. However, the voltage profile in the ERCOT Nodal Operating Guide Section 2 is different from that in the draft PRC-024 (the HV portion in both curves is the same, the LV portion is different). Is this based on knowledge that ERCOT will be changing their voltage curves to those shown in PRC-024? If not, ERCOT should be treated as a Regional Variance like that done for the Quebec Interconnection. Again, if the release of PRC-024-3 and ERCOT updates are not coordinated, there will a lack of clarity and possibile errors in setting.

ITEM 3:

B.R2 – Under certain conditions of large power production and large voltage dips, to protect itself from destructive overcurrents, an inverter may have to stop producing current for up to 20 ms at the start of the voltage dip. It will then very rapidly ramp back to the current reference values in up to an additional 50 ms. Note this reduction in current is only for a maximum time of 70 ms and not for the duration of the voltage dip. Is such a self-protective fast recovery period of low current considered "cease injecting current"? Will it require documentation under R3?

Note also that this is different from an inverter ceasing to inject current for the duration of the voltage dip and then ramping current after voltage recovery over a 500 ms to 1 second period.

ITEM 4:

In some cases, the clean copy of the draft is different from the redlined version.

Page 7 of clean draft - Violation Severity Level Tables R1 - In the Severe VSL cell, the redline document uses terminology “cease injecting current”, the clean document uses terminology “enter momentary cessation”. R2 - In the Severe VSL cell, the redline document uses terminology “cease injecting current”, the clean document uses terminology “enter momentary cessation”. **Page 11** of clean draft D.A.2 - In the Severe VSL cell, the redline document uses terminology “cease injecting current”, then clean document uses terminology “enter momentary cessation”.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. Item 1: It is up to each generator owner to understand how their protection would respond to the voltage profile contained on Attachment 2. The SDT believes that different protection schemes may need to incorporate a cumulative approach to accurately model how their protection will respond to the voltage profile in Attachment 2. Item 2: The team is aware of these differences however the ERCOT Nodal Operating Guide Section 2 is accomplishing a different task than PRC-024-3. Item 3: As written, PRC-024-3 would require invoking R3 if it is necessary to cease injecting current in the no trip zone for machine protection. Item 4: These have been corrected in the current redline and clean version of the standard.	
Donald Lynd - CMS Energy - Consumers Energy Company - 1	
Answer	No
Document Name	

Comment
I did not notice any comments in the SAR addressing a need to change the section "Evaluating Protective Relay Settings" in Attachment 2. In this section the drafting team has removed the option of using the assumptions that the units are at full nameplate real-power output and the power factor is 0.95 lagging. I assume that anyone who previously completed their evaluations using these assumptions would need to reevaluate using the most probable real and reactive loading conditions. This could be a significant expense, particularly for those who contracted the original work and would effectively be starting over. Allowing use of the previous assumptions should provide a similar level of reliability without the added cost. On a related note, item 'a' in this section provides instruction regarding the unit under study, but there is no longer clear instruction for the loading of other units connected to the same transformer. Also related to cost, our existing documentation for wind turbines provides a ride-through curve, but does not indicate when the unit will cease to inject current. For example, one manufacturer's documentation lists a ride-through time at zero percent voltage with a footnote that the converter may stop pulsing during this period. We have attempted to obtain information from one of our manufacturers in support of another NERC PRC Standard, without success to this point. For existing equipment, there is no guarantee the information necessary to comply with the proposed Standard can be obtained.

Likes 0	
Dislikes 0	

Response
Thank you for your comments. The SAR directed the SDT to consider whether to address matters to reinforce that the requirements pertain to point of interconnection. That is the reason for the changes to the "Evaluate Protection Relay Settings" section. The SDT believes that by using the most probably real and reactive loading condition, the wording better reflects the reliability intent of the standard. The SDT also believes the example listed above should be addressed through Compliance Guidance.

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3	
Answer	No
Document Name	
Comment	

: I did not notice any comments in the SAR addressing a need to change the section "Evaluating Protective Relay Settings" in Attachment 2. In this section the drafting team has removed the option of using the assumptions that the units are at full nameplate real-power output and the power factor is 0.95 lagging. I assume that anyone who previously completed their evaluations using these assumptions would need to reevaluate using the most probable real and reactive loading conditions. This could be a significant expense, particularly for those who contracted the original work and would effectively be starting over. Allowing use of the previous assumptions should provide a similar level of reliability without the added cost.

On a related note, item 'a' in this section provides instruction regarding the unit under study, but there is no longer clear instruction for the loading of other units connected to the same transformer.

Also related to cost, our existing documentation for wind turbines provides a ride-through curve, but does not indicate when the unit will cease to inject current. For example, one manufacturer's documentation lists a ride-through time at zero percent voltage with a footnote that the converter may stop pulsing during this period. We have attempted to obtain information from one of our manufacturers in support of another NERC PRC Standard, without success to this point. For existing equipment, there is no guarantee the information necessary to comply with the proposed Standard can be obtained.

Likes 0	
Dislikes 0	

Response

Thank you for your comments. The SAR directed the SDT to consider whether to address matters to reinforce that the requirements pertain to point of interconnection. That is the reason for the changes to the "Evaluate Protection Relay Settings" section. The SDT believes that by using the most probably real and reactive loading condition, the wording better reflects the reliability intent of the standard. The SDT also believes the example listed above should be addressed through Compliance Guidance.

Bridget Silvia - Sempra - San Diego Gas and Electric - 3

Answer	No
Document Name	

Comment

Do not have enough information to determine if this will be cost-effective or not.	
Likes 0	
Dislikes 0	
Response	
Thank you for your response.	
Thomas Foltz - AEP - 5	
Answer	No
Document Name	
Comment	

Because the current comment form provides no area for providing general feedback, or feedback regarding areas beyond those stated within the questions themselves, we have elected to provide such feedback in the response to this question.

AEP does not agree that the proposed modifications provide a cost-effective means of addressing issues in the SAR. AEP continues to recommend removing the reference to “high-side of generator step-up or collector transformer” and allow Generator Owners to utilize the point of interconnection as defined within the FERC filed Interconnection Service Agreement. AEP believes the SDT should take the opportunity to remain consistent with the currently enforceable versions of PRC-024 and FAC-008 and retain the reference to “point of interconnection” but remove the “clarifying text” which we believe instead describes a point of measurement. The definition as presented creates undue compliance burden on the Generator Owner and may negatively impact ride-through capability for renewable resources with generator interconnection facilities of considerable distance. Driven by these concerns, AEP has chosen to vote negative on the proposed draft.

While the currently posted “redline to last posted” document is indeed helpful for seeing the most recently proposed changes, we believe that it should be accompanied by an additional redlined document showing all currently proposed edits-to-date, both additions and deletions, using only the current version subject to enforcement as a baseline (i.e. “redline to last approved”). If only the most recently proposed revisions are shown, incorrect conclusions may be drawn by industry during their review. For example, in the “redline to last posted” document, text in black could be currently included in the version under enforcement or it could instead be text that was

proposed in the previous draft but left unchanged in the latest draft. Similarly, text shown as deleted could be text recently proposed for deletion in the most recent draft, or instead could be text that was proposed for inclusion in the previous draft but then later struck in the latest draft.	
Likes 1	Northern California Power Agency, 5, Hostler Marty
Dislikes 0	
Response	
Thank you for your comments. The currently enforceable standard does use the high-side of the transformer, and the language is consistent with the language in PRC-024-2 footnote 3. A redline to last approved will be posted with final ballot.	
Jeanne Kurzynowski - CMS Energy - Consumers Energy Company - 1,3,4,5 - RF	
Answer	No
Document Name	
Comment	
I did not notice any comments in the SAR addressing a need to change the section “Evaluating Protective Relay Settings” in Attachment 2. In this section the drafting team has removed the option of using the assumptions that the units are at full nameplate real-power output and the power factor is 0.95 lagging. I assume that anyone who previously completed their evaluations using these assumptions would need to reevaluate using the most probable real and reactive loading conditions. This could be a significant expense, particularly for those who contracted the original work and would effectively be starting over. Allowing use of the previous assumptions should provide a similar level of reliability without the added cost. On a related note, item ‘a’ in this section provides instruction regarding the unit under study, but there is no longer clear instruction for the loading of other units connected to the same transformer. Also related to cost, our existing documentation for wind turbines provides a ride-through curve, but does not indicate when the unit will cease to inject current. For example, one manufacturer’s documentation lists a ride-through time at zero percent voltage with a footnote that the converter may stop pulsing during this period. We have attempted to obtain information from one of our manufacturers in	

support of another NERC PRC Standard, without success to this point. For existing equipment, there is no guarantee the information necessary to comply with the proposed Standard can be obtained.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SAR directed the SDT to consider whether to address matters to reinforce that the requirements pertain to point of interconnection. That is the reason for the changes to the "Evaluate Protection Relay Settings" section. The SDT believes that by using the most probably real and reactive loading condition, the wording better reflects the reliability intent of the standard. The SDT also believes the example listed above should be addressed through Compliance Guidance.	
Pamela Hunter - Southern Company - Southern Company Services, Inc. - 1,3,5,6 - SERC, Group Name Southern Company	
Answer	Yes
Document Name	
Comment	
If the existing protection equipment (other than discrete protective relays) are incapable of being set to comply with R1 and/or R2, they should not be required to be changed out and should be permitted to be included in the R3 exclusion option, which has been retained in the current draft. Two other comments regarding the draft and the negative vote explanation: **First item:** Changing the title of the standard implies that the scope of included F and V protection settings has been expanded to non-Generator protection items, e.g. mechanical (turbine), et. al. which used electrical signals in the detection/operation. Disagree with this expansion – no documented need for this change w.r.t. system reliability. **Second item:** A.) Many generator owners, including this one, have already made inverter controls setting adjustments for inverter-based systems to permit ride-through capability with immediate or minimal delay to restart as a result of the recent NERC Alert recommendations on the subject.	

B.) Industry standard P2800 is being written to ensure that future inverter-based electric generating equipment is built with these operational characteristics maximized for grid performance. C.) A recent CAISO tariff amendment which targets mitigating reliability issues caused by inverter-based generators response to grid disturbances related to high voltage transmission system faults or transient voltage excursions. These changes to the tariff will provide the necessary changes to future inverter-based resources. These tariff revisions result from the CAISO's most recent Interconnection Process Enhancements "IPE" stakeholder initiative. The Inverter-based resource task force, too, has issued recommended interconnect agreement suggestions for all transmission service providers to consider when agreeing to connect these types of resources to the grid. The combination of each of these three factors (A, B, and C above) coupled with the absence of system control instability in the current state makes a sufficient case that these changes to PRC-024 are not needed at this time.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The current footnotes in the standard address this situation and additional clarity was provided on excluded equipment. The SDT revisions to the title are not intended to expand the standard, and the team's edits were within the scope of the SC-approved SAR. The applicability section of the standard does not bring in turbine protections. For the second item, the SDT made the necessary changes as required by the SAR.	
Line Dufour - Hydro-Qu?bec Production - 6 - NPCC	
Answer	Yes
Document Name	
Comment	
We have an additional comment about the draft RSAW that is shown on the project page. It doesn't include the two requirements D.A.2 and D.A.5 from the variance for the Quebec Interconnection.	
Likes 0	
Dislikes 0	

Response	
Thank you. We can provide the feedback to Compliance.	
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	
The new and revised language proposed for PRC-024-3 provide a cost-effective means of addressing the most pressing industry concerns expressed in comments to the SAR. ACES appreciates the efforts of NERC and the drafting team, and the opportunity to comment.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment.	
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: Carrie Dixon, Xcel Energy, Inc. , 6; Gerry Huitt, Xcel Energy, Inc., 1, 5, 3; - Amy Casuscelli	
Answer	Yes
Document Name	
Comment	
Xcel Energy is supportive of the modifications propsed. We also submit the following reword of Footnote 4 to assist in readability: "Excludes limitations caused by the setting capability of the frequency and voltage protective relays for the generating resource(s). *This* does not exclude limitations originating in the equipment protected by the relays or frequency and voltage protection that is embedded in control systems."	
Likes 0	
Dislikes 0	
Response	
Thank you for your comments. The SDT had edited the footnote for clarity.	
Wayne Guttormson - SaskPower - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Teresa Cantwell - Lower Colorado River Authority - 5	
Answer	Yes

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Trevor Tidwell - PNM Resources - Public Service Company of New Mexico - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Daniel Gacek - Exelon - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Constantin Chitescu - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chantal Mazza - Hydro-Qu?bec TransEnergie - 2 - NPCC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Larry Heckert - Alliant Energy Corporation Services, Inc. - 4	
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	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Glenn Barry - Los Angeles Department of Water and Power - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Bruce Reimer - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Nick Batty - Keys Energy Services - 9 - SERC	
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	
Michael Goggin - Grid Strategies - 5 - NA - Not Applicable	
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	
Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Glen Farmer - Avista - Avista Corporation - 5	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Davis Jelusich - Public Utility District No. 1 of Chelan County - 6, Group Name Public Utility District No. 1 of Chelan County	
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	
Kim Thomas - Duke Energy - 1,3,5,6 - SERC,RF, Group Name Duke Energy	

Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Garza - FirstEnergy - FirstEnergy Corporation - 4, Group Name FE Voter	
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	
Kevin Conway - Public Utility District No. 1 of Pend Oreille County - 1,3,5,6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Anthony Jablonski - ReliabilityFirst - 10	
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	
Michelle Amarantos - APS - Arizona Public Service Co. - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Chris Wagner - Santee Cooper - 1, Group Name Santee Cooper	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

Response	
Matthew Nutsch - Seattle City Light - 1,3,4,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Jonathan Robbins - Seminole Electric Cooperative, Inc. - 1,3,4,5,6	
Answer	
Document Name	PRC-024-2 - PRC-024-3 (Draft 2) Comments and Questions.docx
Comment	
See additional questions/comments attached.	
Likes 0	
Dislikes 0	
Response	
Thank you for your comment. Item 1: The table specifies whether or not the boundary lines are inclusive or exclusive. Item 2: The SDT notes that the table specifies the requirements before 0.1 seconds.	

Item 3: The table specifies whether or not the boundary lines are inclusive or exclusive. Item 4: The SDT notes that the minimum time is 4.00 seconds, meaning a setting at 4.00 seconds for voltages outside of the no trip zone would be acceptable.	
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	
Westar Energy and Kansas City Power & Light support the Edison Electric Institutes (EEI) Comments	
Likes 0	
Dislikes 0	
Response	
Please see response to EEI.	

End of Report