Comment Report

Project Name:	2016-04 Modifications to PRC-025-1 | PRC-025-2
Comment Period Start Date:	10/30/2017
Comment Period End Date:	12/14/2017
Associated Ballots:	2016-04 Modifications to PRC-025-1 PRC-025-2 AB 2 ST

There were 39 sets of responses, including comments from approximately 126 different people from approximately 93 companies representing 10 of the Industry Segments as shown in the table on the following pages.

Questions

1. The Implementation Plan is proposed to supersede the PRC-025-1 Implementation Plan and become effective no earlier than the phased-in dates for PRC-025-1 with the exception that the SDT has revised the plan to provide a full 60-month and 84-month phased-in implementation those Table 1 Options where the phase overcurrent relay 50 element has been added; and a 24-month and 48-month phased-in implementation for the other Table 1 Options affected by the revisions. Do you agree that the proposed Implementation Plan is reasonable given the proposed revisions? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

2. If you have any other comments on the Standard or documents, please provide them here.

Organization Name	Name	Segment(s)	Region	Group Name	Group Member Name	Group Member Organization	Group Member Segment(s)	Group Member Region
Brandon McCormick	Brandon McCormick		FRCC	FMPA	Tim Beyrle	City of New Smyrna Beach Utilities Commission	4	FRCC
					Jim Howard	Lakeland Electric	5	FRCC
					Lynne Mila	City of Clewiston	4	FRCC
					Javier Cisneros	Fort Pierce Utilities Authority	3	FRCC
					Randy Hahn	Ocala Utility Services	3	FRCC
					Don Cuevas	Beaches Energy Services	1	FRCC
					Jeffrey Partington	Keys Energy Services	4	FRCC
					Tom Reedy	Florida Municipal Power Pool	6	FRCC
					Steven Lancaster	Beaches Energy Services	3	FRCC
					Mike Blough	Kissimmee Utility Authority	5	FRCC
					Chris Adkins	City of Leesburg	3	FRCC
					Ginny Beigel	City of Vero Beach	3	FRCC
ACES Power Marketing	Brian Van Gheem	6	NA - Not Applicable	ACES Standards Collaborators	Greg Froehling	Rayburn Country Electric Cooperative, Inc.	3	SPP RE
					Bob Solomon	Hoosier Energy Rural Electric	1	RF

						Cooperative, Inc.		
					Shari Heino	Brazos Electric Power Cooperative, Inc.	1,5	Texas RE
					Ginger Mercier	Prairie Power, Inc.	1,3	SERC
					Bill Hutchison	Southern Illinois Power Cooperative	1	SERC
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					John Shaver	Arizona Electric Power Cooperative, Inc.	1	WECC
					Ryan Strom	Buckeye Power, Inc.	5	RF
Tennessee Valley Authority	Dennis Chastain	1,3,5,6	SERC	Tennessee Valley Authority	DeWayne Scott	Tennessee Valley Authority	1	SERC
					Ian Grant	Tennessee Valley Authority	3	SERC
					Brandy Spraker	Tennessee Valley Authority	5	SERC
					Marjorie Parsons	Tennessee Valley Authority	6	SERC
Seattle City Light	Ginette Lacasse	1,3,4,5,6	WECC	Seattle City Light Ballot Body	Pawel Krupa	Seattle City Light	1	WECC
					Hao Li	Seattle City Light	4	WECC
					Bud (Charles) Freeman	Seattle City Light	6	WECC
					Mike Haynes	Seattle City Light	5	WECC
					Michael Watkins	Seattle City Light	1,4	WECC
					Faz Kasraie	Seattle City Light	5	WECC

					John Clark	Seattle City Light	6	WECC
					Tuan Tran	Seattle City Light	3	WECC
					Laurrie Hammack	Seattle City Light	3	WECC
Entergy	Julie Hall	6		Entergy/NERC Compliance	Oliver Burke	Entergy - Entergy Services, Inc.	1	SERC
					Jaclyn Massey	Entergy - Entergy Services, Inc.	5	SERC
DTE Energy - Detroit Edison Company	Karie Barczak	3,4,5		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
Lower Colorado River Authority	Michael Shaw	1		LCRA Compliance	Teresa Cantwell	LCRA	1	Texas RE
					Dixie Wells	LCRA	5	Texas RE
					Michael Shaw	LCRA	6	Texas RE
Northeast Power Coordinating Council	Ruida Shu	1,2,3,4,5,6,7,8,9,10	NPCC	RSC no Dominion and ISO-NE	Guy V. Zito	Northeast Power Coordinating Council	10	NPCC
					Randy MacDonald	New Brunswick Power	2	NPCC
					Wayne Sipperly	New York Power Authority	4	NPCC
					Glen Smith	Entergy Services	4	NPCC
					Brian Robinson	Utility Services	5	NPCC
					Bruce Metruck	New York Power Authority	6	NPCC
					Alan Adamson	New York State Reliability Council	7	NPCC

					Edward Bedder	Orange & Rockland Utilities	1	NPCC
					David Burke	Orange & Rockland Utilities	3	NPCC
					Michele Tondalo	UI	1	NPCC
					Laura Mcleod	NB Power	1	NPCC
					David Ramkalawan	Ontario Power Generation Inc.	5	NPCC
					Quintin Lee	Eversource Energy	1	NPCC
					Paul Malozewski	Hydro One Networks, Inc.	3	NPCC
					Helen Lainis	IESO	2	NPCC
					Michael Schiavone	National Grid	1	NPCC
					Michael Jones	National Grid	3	NPCC
					Greg Campoli	NYISO	2	NPCC
					Sylvain Clermont	Hydro Quebec	1	NPCC
					Chantal Mazza	Hydro Quebec	2	NPCC
					Silvia Mitchell	NextEra Energy - Florida Power and Light Co.	6	NPCC
					Michael Forte	Con Ed - Consolidated Edison	1	NPCC
					Daniel Grinkevich	Con Ed - Consolidated Edison Co. of New York	1	NPCC
					Peter Yost	Con Ed - Consolidated Edison Co. of New York	3	NPCC
					Brian O'Boyle	Con Ed - Consolidated Edison	5	NPCC
					Sean Cavote	PSEG	4	NPCC

Midwest Reliability Organization	Russel Mountjoy	10		MRO NSRF	Joseph DePoorter	Madison Gas & Electric	3,4,5,6	MRO
					Larry Heckert	Alliant Energy	4	MRO
					Amy Casucelli	Xcel Energy	1,3,5,6	MRO
					Michael Brytowski	Great River Energy	1,3,5,6	MRO
					Jodi Jensen	Western Area Power Administratino	1,6	MRO
					Kayleigh Wilkerson	Lincoln Electric System	1,3,5,6	MRO
					Mahmood Safi	Omaha Public Power District	1,3,5,6	MRO
					Brad Parret	Minnesota Power	1,5	MRO
					Terry Harbour	MidAmerican Energy Company	1,3	MRO
					Tom Breene	Wisconsin Public Service	3,5,6	MRO
					Jeremy Volls	Basin Electric Power Coop	1	MRO
					Kevin Lyons	Central Iowa Power Cooperative	1	MRO
					Mike Morrow	Midcontinent Independent System Operator	2	MRO
Southwest Power Pool, Inc. (RTO)	Shannon Mickens	2	SPP RE	SPP Standards Review Group	Shannon Mickens	Southwest Power Pool Inc.	2	SPP RE
					J. Scott Williams	City of Utilities of Springfield, MO	1,4	SPP RE
					Louis Guidry	Cleco Corporation	1,3,5,6	SPP RE
					Mike Kidwell	Empire District Electric Company	1,3,5	SPP RE
					Kevin Giles	Westar Energy	1	SPP RE

PPL - Louisville Gas and Electric Co.	Shelby Wade	3,5,6	RF,SERC	Louisville Gas and Electric Company and Kentucky Utilities Company	Charles Freibert	PPL - Louisville Gas and Electric Co.	3	SERC
					Dan Wilson	PPL - Louisville Gas and Electric Co.	5	SERC
					Linn Oelker	PPL - Louisville Gas and Electric Co.	6	SERC

1. The Implementation Plan is proposed to supersede the PRC-025-1 Implementation Plan and become effective no earlier than the phased-in dates for PRC-025-1 with the exception that the SDT has revised the plan to provide a full 60-month and 84-month phased-in implementation those Table 1 Options where the phase overcurrent relay 50 element has been added; and a 24-month and 48-month phased-in implementation for the other Table 1 Options affected by the revisions. Do you agree that the proposed Implementation Plan is reasonable given the proposed revisions? If not, please provide a justification for increasing or decreasing the proposed implementation periods.

Julie Hall - Entergy - 6, Group Name Entergy/NERC Compliance

Answer	No
Document Name	

Comment

Allow 36 months instead of 24 months for the added option per this revision. Generators with 24 month outage schedules will need the additional time, especially nuclear plants.

Likes 0	
Dislikes 0	

Response

Theresa Allard - Minnkota Power Cooperative Inc. - 1

Answer	No
Document Name	

Comment

Recommend providing the same 60-month and 84-month implemenation preiods no matter what aype of protective device, to avoid confusion.

Likes 0	
Dislikes 0	

Response

Russel Mountjoy - Midwest Reliability Organization - 10, Group Name MRO NSRF

Answer	No
Document Name	

Comment

The SDT should provide the same full 60 and 84 month phased-in implementation from the first effective date of PRC-025-2 for any protective devices that apply to footnote 1, of proposed PRC-025-2 (1 Relays include low voltage protection devices that have adjustable settings). The SDT must allow entities appropriate time to adjust to changes in the NERC standard.	
Likes 0	
Dislikes 0	
Response	
William Hutchison - Southern Illinois Power Cooperative - 1	
Answer	No
Document Name	
Comment	
Comments submitted as part of ACES comments	
Likes 0	
Dislikes 0	
Response	
Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators	
Answer	No
Document Name	
Comment	
We appreciate the SDT's inclusion of a transition period between implementation plans for this standard. However, we find the phased-in approach based on varying options of relay loadability evaluation criteria confusing. For load responsive protective relays that are currently subject to the standard, the current implementation plan could possibly supersede the proposed implementation plan. We believe a phased-in implementation period should clearly begin on the effective date of the proposed standard and independent of specific relay loadability evaluation criteria. If an entity determines that replacement or removal of the relay is not necessary, then the entity should have 24 months after the standard's effective date to make other associated changes. However, if the entity determines relay replacement or removal is necessary, then the entity should have 48 months after the standard's effective date for procurement and installation of the new relay. With the inclusion of the element 50 relay in this proposed standard, the SDT's 60-month and 84-month respective implementation period is tolerable.	
Likes 0	
Dislikes 0	
Response	

Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	

Maryanne Darling-Reich - Black Hills Corporation - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
BHC feels the IP is reasonable.	
Likes 0	
Dislikes 0	
Response	

Thomas Foltz - AEP - 5	
Answer	Yes
Document Name	
Comment	
AEP believes this most recently proposed Implementation Plan is reasonable.	
Likes 0	
Dislikes 0	
Response	

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC, Group Name Seattle City Light Ballot Body	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Mike Smith - Manitoba Hydro - 1	
Answer	Yes
Document Name	
Comment	
Likes 1	Manitoba Hydro , 5, Xiao Yuguang
Dislikes 0	
Response	

Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
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	
Ann Ivanc - FirstEnergy - FirstEnergy Solutions - 6	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company	
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	
Ruth Miller - Exelon - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	

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

Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Laura Nelson - IDACORP - Idaho Power Company - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Douglas Webb - Douglas Webb On Behalf of: Harold Wyble, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; James McBee, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jessica Tucker, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; Jim Flucke, Great Plains Energy - Kansas City Power and Light Co., 5, 1, 3, 6; - Douglas Webb	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
larry brusseau - Corn Belt Power Cooperative - 1	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Kevin Salsbury - Berkshire Hathaway - NV Energy - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Mark Riley - Associated Electric Cooperative, Inc. - 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	

Neil Swearingen - Salt River Project - 1,3,5,6 - WECC	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Dennis Chastain - Tennessee Valley Authority - 1,3,5,6 - SERC, Group Name Tennessee Valley Authority	
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	
Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name SPP Standards Review Group	
Answer	Yes
Document Name	
Comment	

Likes 0	
Dislikes 0	
Response	
Douglas Johnson - American Transmission Company, LLC - 1	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Adkins, City of Leesburg, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Ruida Shu - Northeast Power Coordinating Council - 1,2,3,4,5,6,7,8,9,10 - NPCC, Group Name RSC no Dominion and ISO-NE	
Answer	Yes
Document Name	
Comment	
Likes 0	

Dislikes 0	
Response	
David Ramkalawan - Ontario Power Generation Inc. - 5	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
Michael Shaw - Lower Colorado River Authority - 1, Group Name LCRA Compliance	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	
David Jendras - Ameren - Ameren Services - 3	
Answer	Yes
Document Name	
Comment	
Likes 0	
Dislikes 0	
Response	

Darnez Gresham - Darnez Gresham On Behalf of: Annette Johnston, Berkshire Hathaway Energy - MidAmerican Energy Co., 1, 3; - Darnez Gresham	
Answer	
Document Name	
Comment	
Support Comments submitted by the MRO NERC Standards Review Forum (NSRF)	
Likes 0	
Dislikes 0	
Response	

2. If you have any other comments on the Standard or documents, please provide them here.

David Jendras - Ameren - Ameren Services - 3

Answer	
Document Name	

Comment

For figure 2, identify that busses B, C, and D and their interconnecting lines as 'the transmission system' for clarity. We believe that this will help clarify that only reverse-looking or non-directional elements are within PRC-025 scope.

Likes 0	
Dislikes 0	

Response

George Brown - Acciona Energy North America - 5

Answer	
Document Name	

Comment

First, the PRC-025 Standard Drafting Team (SDT) has done an excellent job of addressing application 5B as it relates to dispersed power producing resources. However, I still have a concern how PRC-025 is applied to other equipment at the generation asset. My concern is in relation to equipment that is not designed to operate at 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor and this equipment is at a facility that was built prior to PRC-025 becoming effective/enforceable. My specific concern relates to the following Applications and Options in Attachment 1, Table 1.

- Application: Relays installed on generator … only (including inverter-based installations).
- Options: 10, 11 & 12

- Application: Relays installed on the high … s that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant. (except that Elements may also supply generating plant loads.) – connected to asynchronous generators only (including inverter-based installations).
- Options: 17, 18 & 19

For example, let's say that a dispersed power producing resource's main power transformer (MPT) is only rated to run continuously at 110% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor or what is better known as a original equipment manufacturer damage curve. If an entity was to set its respective protection systems for that MPT to ≥ 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor then the MPT is no longer properly protected, has become a safety issue for personnel that work around the MPT and at risk of catastrophic failure.

I would like to recommend the SDT add similar language as drafted for application 5B to Options 10, 11, 12, 17, 18 & 19. Perhaps, even taking it a step further and adding in some sort of “grandfathering” language, so that facilities that are connected/constructed after the effective/enforcement of PRC-025 would be designed to meet the 130%, while facilities built prior can have their protection systems set to the maximum allowable level based on the equipment installed at the facility.

Essentially, there is potential that many dispersed power producing resources will have equipment throughout the site that will not allow them to set protection systems to ≥ 130% of the calculated current derived from the maximum aggregate nameplate MVA output at rated power factor while still providing adequate protection to the equipment necessary for the safe and reliable operation of the facility.

Likes 0	
Dislikes 0	

Response

Brandon McCormick - Brandon McCormick On Behalf of: Carol Chinn, Florida Municipal Power Agency, 6, 4, 3, 5; Chris Adkins, City of Leesburg, 3; Chris Gowder, Florida Municipal Power Agency, 6, 4, 3, 5; Ginny Beigel, City of Vero Beach, 3; Joe McKinney, Florida Municipal Power Agency, 6, 4, 3, 5; Ken Simmons, Gainesville Regional Utilities, 1, 3, 5; Lynne Mila, City of Clewiston, 4; Richard Montgomery, Florida Municipal Power Agency, 6, 4, 3, 5; Tom Reedy, Florida Municipal Power Pool, 6; - Brandon McCormick, Group Name FMPA

Answer	
Document Name	

Comment

It would seem that item number 5 of the SAR was not completed. For example, the setting criteria for Table 1 still has language such as “…shall be set less than the calculated impedance derived from 115% of: ….”

From item number 5 of the SAR, **“Clarify that multiple methods/curve types are acceptable so long as the applied protection *does not trip* the generator(s) under the conditions described in the table. For example, using such language could more clearly allow use of blinders, non - mho relay characteristics and other schemes in which the relay’s initial measurement may detect a condition (e.g., may “pickup”) but the relay is blocked from operating.”**

Since the Table 1 descriptors still refer to an “impedance element setting”, the issue still exists despite removing the term “Pickup”, which was only part of what was needed. Using the phrase “shall not trip” rather than the phrase “shall be set” in the Table 1 Setting Criteria will accomplish the goal of item number 5. Due to the SAR not being complete, FMPA is casting a negative ballot.

Likes 0	
Dislikes 0	

Response

Douglas Johnson - American Transmission Company, LLC - 1

Answer	

Document Name	
Comment	

No comments.

Likes 0	
Dislikes 0	
Response	

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

Answer	
Document Name	
Comment	

N/A

Likes 0	
Dislikes 0	
Response	

Rachel Coyne - Texas Reliability Entity, Inc. - 10

Answer	
Document Name	
Comment	

Attachment 1 states that relay setting criteria values are derived from the unit's maximum gross Real Power capability, in megawatts (MW), as reported to the Transmission Planner. This does not account for the scenario when the Generator Owner (GO) does not provide accurate capability data to the Transmission Planner (TP). Texas RE suggests it would be more effective to base the Real Power capability on calculations used for the determination of Facility Ratings or the Real Power capability verification performed for MOD-025-2.

As previously requested, Texas RE asks the SDT consider providing a justification of the "Long Term Planning" time horizon as it has a significant impact on Penalty calculations. The phrase "shall apply settings" is indicative of a Real-time or near Real-time action. While planning activities have to recognize proposed settings (and reflect current setting for those relays not subject to change), ultimately the setting occurs in a much shorter time horizon than "Long-term Planning".

Texas RE also noticed the following:

- In the redline version, the header still has "-1" throughout some of the change management documents of the Standard. Texas RE did notice the header was changed to PRC-025-2 in the clean version.
- Section "C: Compliance 1.3 Compliance Monitoring and Assessment Processes" appears to not follow the template for Results Based Standards. This version lists out the various compliance monitoring processes, whereas the template states: As defined in the NERC Rules of Procedure, "Compliance Monitoring and Enforcement Program" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated Reliability Standard.
- The Violation Severity Level table does not follow the template for Results Based Standards.
- The introduction in Attachment 1, references "3.2 Facilities". Facilities are listed in section 4.2 of the standard.

Likes 0	
Dislikes 0	

Response

Brian Van Gheem - ACES Power Marketing - 6 - NA - Not Applicable, Group Name ACES Standards Collaborators

Answer	
Document Name	

Comment

1. We believe a performance-based criteria could be established for the Violation Severity Levels (VSLs) for this standard, similar to what is present for NERC Reliability Standard PRC-005-6. In that standard, the severity is based on a specific percentage of Components the applicable entity failed to maintain in accordance with minimum maintenance activities and maximum maintenance intervals. In this standard, a severe VSL is assessed when the entity fails to apply the required settings for any one load responsive protective relay. We recommend a gradated approach based on the percentage of load-responsive protective relays where the entity failed to apply settings. This would complement the list of load-responsive protective relays identified as requested evidence in the standard's RSAW.
2. We ask the SDT to include hyperlinks for documents referenced as footnotes. The presence of multi-lined web addresses can inadvertently include extra spaces that corrupts or disables the link.
3. We thank you for this opportunity to provide these comments.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

We appreciate the drafting team's consideration of our comments submitted on PRC-025-2, Draft 1. We believe the drafting team's response to our comment under Question 12 should be added as a footnote to Table 1. Specifically, consider adding the following as a clarifying footnote to Table 1: "The "gross MW capability reported to the Transmission Planner" is based upon NERC Reliability Standard MOD-025-2. The Generator Owner may base settings on a capability (e.g., nameplate) that is higher than what is reported to the Transmission Planner. If different seasonal capabilities are reported, the maximum capability could be used for the purposes of this standard as a minimum requirement."

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	

Comment

Support Comments submitted by the MRO NERC Standards Review Forum (NSRF)

Likes 0	
Dislikes 0	

Response

William Hutchison - Southern Illinois Power Cooperative - 1

Answer	
Document Name	

Comment

Comments were submitted as part of ACES Commnets.

Likes 0	
Dislikes 0	

Response

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

Answer	
Document Name	
Comment	
None	
Likes 0	
Dislikes 0	
Response	
Rick Applegate - Tacoma Public Utilities (Tacoma, WA) - 6	
Answer	
Document Name	
Comment	
Question for drafting team: “If a line connecting the GSU transformer(s) to the Transmission system has a load (that is not generating plant load) tapped to it, would Options 14, 15, or 16 apply at the remote end of the line? Would it apply at the high-side of the GSU transformer(s)? If the answer to both questions above is ‘no,’ then, if there are two lines connecting the GSU transformer(s) to the Transmission system, and one line has a load (that is not generating plant load) tapped to it, would Options 14, 15, or 16 apply at the high-side of the GSU transformer(s)?”	
Likes 0	
Dislikes 0	
Response	
Ruth Miller - Exelon - 5	
Answer	
Document Name	
Comment	
In the previous request for comments Exelon requested that the Project 2016-04 SDT evaluate the proposed fault detector settings associated with pilot wire communication systems. Specifically, Exelon stated in the response to Question 2 that "[c]alculations performed to calculate the settings for these type of relays show that the settings are very close to the 3-phase fault current contributed from the generator in cases where sub-transient reactance of the machine is at a high value. This will compromise the protection scheme because the changes proposed will make the protection scheme very insensitive. In case of a high resistance phase-to-ground fault, the protection scheme will not pick up the fault at the generator end. In some extreme cases, the fault detector relay (67 or 50), if set according to the current draft PRC-025 guidelines, may have to depend on the field forcing provided by	

the Automatic Voltage Regulator (AVR) before the fault current reaches the setpoint. This will induce unnecessary delays in the protective action and may cause more damage to the BES element."

The SDT response to Exelon's comment was that this issue was "beyond the scope of the drafting team's work to revise PRC-025-1 as described in the SAR" and that an entity might have to "employ alternative protection schemes to achieve the loadability requirements and fault protection." Exelon does not agree that this is outside the scope of the SAR given consideration item (2) in the SAR specifically states that this project is to address the inclusion or exclusion of the 50 element.

To address our concerns, Exelon requests the following changes:

1. The fault detector relays used in communication systems should be deleted from the scope of this standard because these particular relays are subject to misoperation only when the communication system has failed and there is a concurrent disturbance on the grid.
2. If there is any issue with a communication system and if the whole pilot protection scheme becomes a simple overcurrent relay, that condition is alarmed. Therefore, this condition would only exist for a short duration. To fix this condition the SDT can add a requirement to remedy this condition within a certain timeframe (e.g., correct condition within three months) and if not resolved then setpoints of 67 or 50 should be raised.
3. If the SDT still wants to retain these relays within the scope, then Exelon requests that the existing setting criteria should be modified as follows:
    i. “Minimum of the criteria 15a (or 15b) or 25% of the current contribution from the generator using a pre-fault voltage of 1.0 pu, generator sub-transient unsaturated reactance, and the main power transformer positive sequence reactance."

Likes 0	
Dislikes 0	

Response

Shelby Wade - PPL - Louisville Gas and Electric Co. - 3,5,6 - SERC, Group Name Louisville Gas and Electric Company and Kentucky Utilities Company

Answer	
Document Name	

Comment

By adding the phrase “except that” to “Elements that connect the GSU transformer(s) to the Transmission system that are used exclusively to export energy directly from a BES generating unit or generating plant, except that Elements may also supply generating plant loads.” in multiple places throughout the document, ambiguity is increased rather than decreased. LKE suggests replacing these instances with full, clearly worded sentences.

Likes 0	
Dislikes 0	

Response

Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE

Answer	
Document Name	PRC-025 modifications drawing.docx

Comment

Xcel Energy has concerns that the changes to the "Application" column for Options 7a-7c, 8a-8c, and 9a-9c are somewhat misleading and the description is inconsistent with Figure 5. We do acknowledge that this is partially a carryover issue from PRC-025-1.

The "Application" column for options 7, 8 & 9 describe "Relays installed on the generator side of the Generator step-up transformer..." Figure 5 shows that the current transformers for the load dependent relays to which options 7-9 are applicable are actually applied on the generator or the generator breaker and not specifically on the low side of the GSU. Note that many microprocessor based generator protection relays allow you to select the signal source for the current input to the 21 function such that either neutral or line side current transformers may be used for the current signal input to the 21 device associated with the generator. In other words, not all generator load dependent relays are fed neutral side current transformers. From this perspective, it would be unclear whether the entity should be using option 1a-1c or option 7a-7c for evaluating the loadability of the 21 function or options 2a-2c or option 8z-8c for the 50/51 functions.

Note that on Figure 5, the location of the generator breaker relative to the generator bus tap to the UAT is incorrect for most typical applicactions. In most applications when a generator breaker is provided, it will be on the generator bus between the generator and the bus tap to the UAT so that the UAT remains in service from the GSU when the generator breaker is open and the generator is offline. There would be operational value in a generator breaker between the UAT tap and GSU LV winding as shown in Figure 5. By moving the location of the generator breaker to the correct location between the generator and UAT bus tap on Figure 5, all inconsistency would be elimated and would greatly improve the clarity of the differences between options 1 vs. 7 and 2 vs. 8. See attached file for markup of Figure 5.

Based on the criteria included in the "settings criteria" colum for options 1, 2, 7 & 8, the key difference to use when determining which option to use is dependent on if the current transformer feeding the load dependent relay includes measurement of current flowing to the UAT in addition to that flowing to the LV winding of the GSU from the generator.

Beyond the above issue with the description clarity, we also have the following technical concerns with options 7 & 8 vs. options 1 & 2:

1. In many instances, in addition to the unit connected auxiliary transformer, a plant also likely has a 100% power capable system connected auxiliary transformer. In this case, the amount of power the plant would be capable of putting out would, to the system, be greater and the settings of any load dependent relay when the plant is fed from the system connected aus, should be based on that capability and calculated per option 1 or 2 and not for the lower value of aggregate power as allowed by option 7 or 8 - regardless of the location of the CT used to feed the load dependent relay. If an entity's reported max gross MW value is based on the gross output when fed from the system connected auxiliary source, then the entity should have to use option 1 or 2 regardless of the configuration of the current transformer relative to the unit connected auxiliary transformer. Option 7 or 8 should only be allowed if the max gross MW reported is based on the reduced output available when the unit is receiving auxiliary power from the unit connected auxiliary transformer.
2. The differences in determining real power between options 1 and 2 vs. 7 adn 8 is understandable, but it is unclear why the reactive power used in option 7 & 8 are calculated differently than that used in options 1 & 2. What is the technical justification for the difference? The response of the machine to depressed grid voltages and field forcing capability will be the same regardless of where the load dependent relay current transformer is located relative to the aux power tap. Using a reduced value for field forcing MVAR based on aggregate MW output rather than a MW value based strictly on nameplate MVA and rated pf does not seem justified.

Likes 0	
Dislikes 0	

Response	
Karie Barczak - DTE Energy - Detroit Edison Company - 3,4,5, Group Name DTE Energy - DTE Electric	
Answer	
Document Name	
Comment	
The Exclusions section should also exclude the following protection system based on footnote 1 in the Applicability Section: Low voltage protection devices that do not have adjustable settings.	
Likes 0	
Dislikes 0	
Response	
Tom Haire - Rutherford EMC - 3	
Answer	
Document Name	
Comment	
Section 4.2.5 should have a minimum threshhold.	
Likes 0	
Dislikes 0	
Response	
Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC	
Answer	
Document Name	
Comment	
None	
Likes 0	

Dislikes 0	
Response	

Supplemental to comments | Xcel Energy

Project 2016-04 Modifications to PRC-025-1