# Consideration of Comments

**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

There were 39 sets of responses, including comments from approximately 126 different people from approximately 93 companies representing the 10 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, Standards and Education Howard Gugel (via email) or at (404) 446-9693.

**Summary Consideration**

The standard received overwhelming support at 88.25% approval, a seven point increase over the initial ballot. The increase in approval is attributed to the changes the drafting team made to the Implementation Plan. Namely, allowing a phased-in implementation of 60/84 months for the 50 relay element and 24/48 for other revisions.

A few comments expressed concern that a phased-in approach to the Implementation Plan is confusing and should be based solely off of the regulatory approval date. The drafting team did not agree with commenters on their rationale for increases or changes to the Implementation Plan or that the phased-in approach was confusing.

Several commenters suggested excellent non-substantive tweaks to the standard while other raised technical questions. The drafting team addressed the following non-substantive revisions:

1. Added a demarcation line to the figures to highlight where the Transmission system began.
2. Updated the Compliance section of the standard to the current template language.
3. Updated the Violation Severity Level (VSL) table to the current template by removing the Violation Risk Factor (VRF) and Time Horizon columns.
4. Corrected the Attachment 1 reference to Facilities from 3.2 to 4.2.

Technical issues included the following:

1. One concern about the 130% setting for asynchronous resources at the generator step-up transformer. The drafting team noted that protective relays that detect overloads are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions are exempt from the standard and should be employed where thermal protection of equipment is a concern. The expectation for loadings less than 130% would be for overloading conditions rather than fault conditions.
2. A concern that the drafting team had not met the objective of item #5 of the Standards Authorization Request. The drafting team disagreed and believes it has met the spirit of item #5 by removing the term “Pick Up,” which aligns with the standard’s purpose to set relays a level to prevent unnecessary tripping of generators.
3. One comment suggested using gross Real Power as determined by Facility ratings. The drafting team noted that Mega-Watt (MW) value (gross Real Power capability) reported to the Transmission Planner under PRC-025-2 is a minimum criteria for the determination of settings. Requiring the use of Facility ratings may not be indicative of the generator capability and could affect the sensitivity of the protection settings.
4. Another comment requested the Requirement R1 VSL to be based on a percentage of missed settings rather than per relay basis. The drafting team noted that the construction of the Requirement does not lend itself to using a graduated VSL.
5. Although the standard bases its calculations on the MOD-025 standard (generator verification) for gross MW value reported to the Transmission Planner as a minimum value, the drafting team was not inclined to add that reference to the standard.
6. One comment questioned how an interconnecting line would be handled if it were tapped with load. The drafting team responded that the Applicability section of the standard would determine whether the line was applicable to PRC-025 or not. The line could be applicable to PRC-023 (Transmission Loadability), however, in any case the entity should use good engineering judgement if a line is not applicable to the standard and is affected by generator output (i.e., loadability).
7. Another single comment illustrated a specific protection scheme and requested a revision to allow an exception to the condition. The drafting team did not agree an exception was appropriate and noted that an entity may be required to remove or replace relays in order to meet the requirement of the standard.

## 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.**

### 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 |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Organization Name | Name | Segment(s) | Region | Group Name | Group Member Name | Group Member Organization | Group Member Segment(s) | Group Member Region |
|---|---|---|---|---|---|---|---|---|
| | | | | | 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 Cooperative, Inc. | 1 | RF |
| | | | | | 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 |

| Organization Name | Name | Segment(s) | Region | Group Name | Group Member Name | Group Member Organization | Group Member Segment(s) | Group Member Region |
|---|---|---|---|---|---|---|---|---|
| | | | | | 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 |

| Organization Name | Name | Segment(s) | Region | Group Name | Group Member Name | Group Member Organization | Group Member Segment(s) | Group Member Region |
|---|---|---|---|---|---|---|---|---|
| | | | | | 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 |

| Organization Name | Name | Segment(s) | Region | Group Name | Group Member Name | Group Member Organization | Group Member Segment(s) | Group Member Region |
|---|---|---|---|---|---|---|---|---|
| | | | | | 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 |

| Organization Name | Name | Segment(s) | Region | Group Name | Group Member Name | Group Member Organization | Group Member Segment(s) | Group Member Region |
|---|---|---|---|---|---|---|---|---|
| | | | | | 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 |

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|---|---|---|---|---|---|---|---|---|
| | | | | | 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 |

| Organization Name | Name | Segment(s) | Region | Group Name | Group Member Name | Group Member Organization | Group Member Segment(s) | Group Member Region |
|---|---|---|---|---|---|---|---|---|
| | | | | | 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 |

| Organization Name | Name | Segment(s) | Region | Group Name | Group Member Name | Group Member Organization | Group Member Segment(s) | Group Member Region |
|---|---|---|---|---|---|---|---|---|
| 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 |

| Question 1 | |
|---|---|
| 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** | |
| Thank you for your comment. The added Option 5b provided an additional means to address loadability on asynchronous resources (not nuclear) and is not expected to create significant work for the entity. Therefore, the drafting team is keeping the current implementation phased-in periods at 24 and 48 months from regulatory approval for setting changes or equipment retirement/replacement, respectively. The 50 element, which could impact nuclear facilities, has been provided a 60 and 84 month implementation period for setting changes or equipment retirement/replacement, respectively. | |
| **Theresa Allard - Minnkota Power Cooperative Inc. - 1** | |
| **Answer** | No |
| **Document Name** | |

| Question 1 | |
|---|---|
| **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** | |
| Thank you for your comment. The drafting team extended the time periods for implementation to address components of the standard that were revised based on comments from the initial posting and subsequent outreach. The relays that were not affected by the revisions will not be phased-in any earlier than the original effective dates of October 1, 2019 for setting changes and October 1, 2021 for removal/replacement. | |
| **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** | |
| Thank you for your comment. Footnote 1 has not introduced any new relays into the standard and was added only to provide clarification for low voltage applications that meet the applicability of the standard. | |
| **William Hutchison - Southern Illinois Power Cooperative - 1** | |

| Question 1 | |
|---|---|
| **Answer** | No |
| **Document Name** | |
| **Comment** | |
| Comments submitted as part of ACES comments | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| Thank you for your comment. Please see the response to ACES' comment(s). | |
| **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 | |

| Question 1 | |
|---|---|
| **Response** | |
| Thank you for your comment. The drafting team extended the time periods for implementation to address components of the standard that were revised based on comments from the initial posting and subsequent outreach. The relays that were not affected by the revisions will not be phased-in any earlier than the original effective dates of October 1, 2019 for setting changes and October 1, 2021 for removal/replacement. | |
| **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** | |

| Question 1 | |
|---|---|
| Thank you for your comment. | |
| **Thomas Foltz - AEP - 5** | |
| **Answer** | Yes |
| **Document Name** | |
| **Comment** | |
| AEP believes this most recently proposed Implementation Plan is reasonable. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| Thank you for your comment. | |
| **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** | |

| Question 1 | |
|---|---|
| **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** | |

| Question 1 | |
|---|---|
| | |
| **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** | |

| Question 1 | |
|---|---|
| **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** | |

| Question 1 | |
|---|---|
| | |
| **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** | |

| Question 1 | |
|---|---|
| | |
| 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** | |

| Question 1 | |
|---|---|
| | |
| **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** | |

| Question 1 | |
|---|---|
| | |
| 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** | |
| | |

| Question 1 | |
|---|---|
| **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** | |
| | |

| Question 1 | |
|---|---|
| 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 | |

| Question 1 | |
|---|---|
| **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** | |

| Question 1 | |
|---|---|
| **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** | |
| Thank you for your comment. Please see the response to the MRO NSRF. | |

| Question 2 | |
|---|---|
| **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** | |
| Thank you for your comment. The drafting team has updated Figures 1, 2, and 3 with a demarcation line labeled “Transmission System” for added clarity. | |
| **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. | |

## Question 2

- Application: Relays installed on generator-side of the Generator step-up transformer(s) connected to asynchronous generators only (including inverter-based installations).

- Options: 10, 11 & 12

- Application:  Relays installed on the high-side of the GSU transformer,15 including relays installed on the remote end of line, for 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.) – 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.

| | |
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| Likes     0 | |
| Dislikes     0 | |

**Response**

Thank you for your comment. The drafting team does not agree that alternatives for Options 10, 11, 12, 17, 18, and 19 in Table 1 need to be included to address equipment that is not installed and set to operate at 130% of the calculated current based on the maximum

| Question 2 | |
|---|---|
| aggregate nameplate MVA. Protective relays that detect overloads and are designed only to respond in time periods which allow an operator 15 minutes or greater to respond to overload conditions are exempt from the standard and should be employed where thermal protection of equipment is a concern. The expectation for loadings less than 130% would be for overloading conditions rather than fault conditions. | |
| **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: …."<br><br>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."**<br><br>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** | |

| Question 2 | |
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| Thank you for your comment. The Standards Authorization Request (SAR) has been met by eliminating the term “Pick Up,” which aligns with the standard’s purpose to set relays to a level to prevent unnecessary tripping of generators during a system disturbance for conditions that do not pose a risk of damage to the associated equipment. The standard encourages entities to reduce the reach of their relays, which is originally what initiated the standards PRC-023 and PRC-025 as well as improving loadability during depressed voltages.<br><br>If an entity applies blinders to the existing relays, implementation of lenticular characteristic relays, or implementation of load encroachment characteristics, then the entity will need to demonstrate how it achieves the intent to not trip for the conditions described in the standard. See PRC-025-2 Application Guidelines Section “Phase Distance Relay – Directional Toward Transmission System (e.g., 21)” for more information. | |
| **Douglas Johnson - American Transmission Company, LLC - 1** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| No comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| Thank you for your comment. | |
| **Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP RE, Group Name** SPP Standards Review Group | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| N/A | |

| Question 2 | |
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| 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.

| Question 2 | |
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| • The Violation Severity Level table does not follow the template for Results Based Standards.<br><br>• The introduction in Attachment 1, references "3.2 Facilities". Facilities are listed in section 4.2 of the standard. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| Thank you for your comment.<br><br>The MW value (gross Real Power capability) reported to the Transmission Planner under MOD-025 is a minimum criteria for the determination of settings under PRC-025-2. Requiring the use of Facility ratings may not be indicative of the generator capability and could affect the sensitivity of the protection settings.<br><br>The drafting team contends that a time horizon of "Long-term Planning" is correctly applied to Requirement R1 and is consistent with other similar requirements for setting protective relays.<br><br>Other:<br>• The software for creating the redline version did not correctly present the version change in the header. The drafting team will review redlines closer prior to posting.<br>• The Compliance Enforcement Authority information has been updated to the template language.<br>• The "VRF" column of the Violation Severity Level table has been removed to reflect the current template.<br>• The reference to 3.2 Facilities in Attachment 1 has been corrected. | |
| **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 | |

| Question 2 | |
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| 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.<br>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.<br>3. We thank you for this opportunity to provide these comments. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| Thank you for your comment.<br>1. The concept of applying a graduated Violation Severity Level for Requirement R1 seems logical; however, the PRC-025 and PRC-005 performance is slightly different. In PRC-025, the performance is per relay and in PRC-005 it is based on a set of relays rather than individual. Therefore, the VSL must be based on a per relay violation and remain as written.<br>2. The drafting team will add the hyperlink to the documents as well as leaving the URL for reference.<br>3. Thank you for commenting. | |
| **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 | |

| Question 2 | |
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| 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** | |
| Thank you for your comment. The initial drafting team, as well as this drafting team, did not include the reference to the MOD-025-2 standard to avoid cases of version changes or where standards may become combined and the reference would become invalid. The language used in PRC-025 mimics the MOD-025 language. Additionally, there has been significant outreach to make the connection with the MOD-025 standard. | |
| **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** | |
| Thank you for your comment. Please see the response provided to the MRO NSRF. | |
| **William Hutchison - Southern Illinois Power Cooperative - 1** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |

| Question 2 | |
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| Comments were submitted as part of ACES Commnets. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| Thank you for your comment. Please see the response provided to ACES' comment(s). | |
| **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: | |

| Question 2 | |
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| "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)?<br><br>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** | |
| Thank you for your comment. The drafting team notes that the entity would need to determine the applicability of the line in question and apply the appropriate Reliability Standard. For example, use PRC-025 for lines 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 and for other lines use PRC-023 where appropriate. In the first case above, the applicable Element would be from the generating plant, including the high-side of the generating step-up transformer to the point tapped by the load. In the second case, the applicability of the Element remains unchanged by the tapped load.<br><br>The drafting team acknowledges the above situation poses a unique circumstance with respect to the narrow applicability (i.e., no load serving); however, an entity should use good engineering judgement and apply the appropriate loadability settings (i.e., PRC-023 or PRC-025) to relays on Elements that are not specifically applicable to a Reliability Standard. | |
| **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 | |

| Question 2 | |
|---|---|
| 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."<br><br>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.<br><br>To address our concerns, Exelon requests the following changes:<br><br>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.<br>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.<br>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:<br>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** | |

| Question 2 | |
|---|---|
| Thank you for your comment. The drafting team understands the specifics of this unique case; however, the standard recognizes that an entity may need to replace or remove equipment that cannot achieve the intent of the standard while providing reliable fault protection. | |
| **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** | |
| Thank you for your comment. The drafting team notes that the phrase was added to make clear that it is acceptable for 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 to also serve plants loads. This phrasing was corrected in version two because the original phrasing was not a complete sentence. | |
| **Amy Casuscelli - Xcel Energy, Inc. - 1,3,5,6 - MRO,WECC,SPP RE** | |
| **Answer** | |
| **Document Name** | PRC-025 modifications drawing.docx |
| **Comment** | |

## Question 2

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.

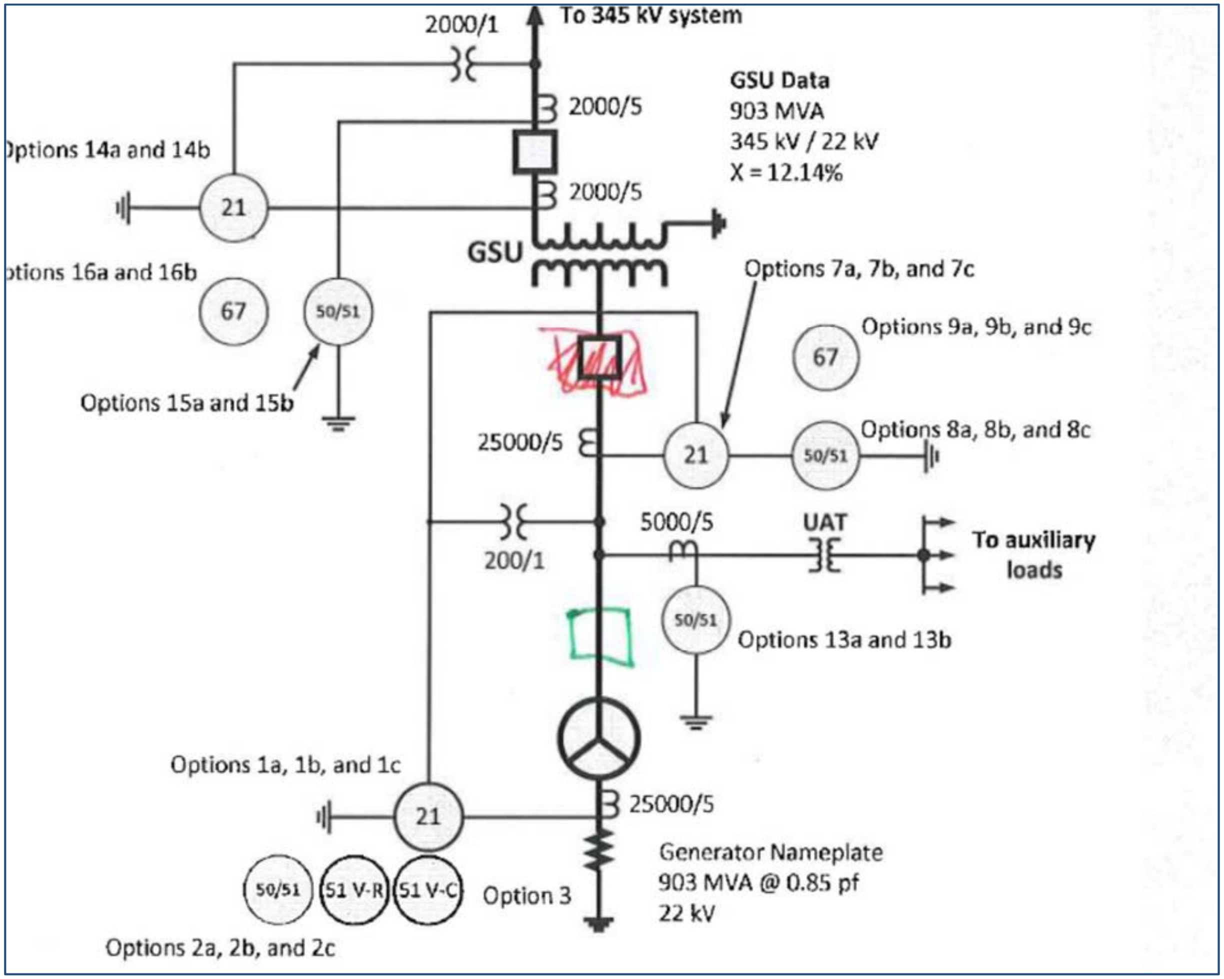
Based on the criteria included in the "settings criteria" colum for options 1, 2, 7 & 8, the key difference to use when determining which option to use is dependent on if the current transformer feeding the load dependent relay includes measurement of current flowing to the UAT in addition to that flowing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

| Question 2 |
| --- |
| 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.<br><br>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. |

## Question 2

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| Likes 0 | |
| Dislikes 0 | |

**Response**

| Question 2 | |
|---|---|
| Thank you for your comment. Options 1a-1c and 7a-7c are differentiated by where the current transformer (CT) is located and not the breaker location. Options 2a-2c and 8a-8c are also differentiated by where the current transformer (CT) is located and not the breaker location. Options 7a-7c and 8a-8c are generally transmission related to address varying entity configurations. For example, where a Transmission Owner owns the generator step-up (GSU) transformer. Option 1a-1c and 2a-2c are directed to Generator Owner protection relaying.<br><br>The representation of the breaker in Figure 5 is for illustration and may not be representative of all configurations.<br><br>Technical response:<br>1. PRC-025 calculations are based upon the gross Megawatt Capability (MW) value reported to the Transmission Planner under MOD-025 and not the net MW. PRC-025 also does not take into account any deductions in MW for a unit auxiliary transformer (UAT) that is connected on the generator bus or to the system. Option 1a-1c does not use the term "aggregate" because it is addressing a single generating unit. Options 7a-7c and 8a-8c may include multiple generators connected to a single GSU transformer; therefore, the "aggregate" gross MW capability must be used in the determination of settings.<br>2. There is no difference in determining the Real Power or Reactive Power for Options 1a-1c/2a-2c and Options 7a-7c/8a-8c. The only difference is that Options 7a-7c and 8a-8c account for where there are multiple (i.e., "aggregate") generators connected to a single GSU transformer. | |
| **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** | |

| Question 2 | |
|---|---|
| Thank you for your comment. The drafting team has added the exclusion in Attachment 1. | |
| **Tom Haire - Rutherford EMC - 3** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| Section 4.2.5 should have a minimum threshhold. | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| Thank you for your comment. Facilities in Section 4.2.5 does not include a threshold because the applicability is driven by whether the resource(s) in Section 4.2 meets the I-4 Inclusion of the Bulk Electric System definition as stated in the Glossary of Terms Used in NERC Reliability Standards. | |
| **Aaron Cavanaugh - Bonneville Power Administration - 1,3,5,6 - WECC** | |
| **Answer** | |
| **Document Name** | |
| **Comment** | |
| None | |
| Likes 0 | |
| Dislikes 0 | |
| **Response** | |
| | |

**End of Report**