Consideration of Comments

Project Name: 2007-06 System Protection Coordination | PRC-027-1 & PRC-001-1.1(ii)

Comment Period Start Date: 7/29/2015

Comment Period End Date: 9/11/2015

Associated Ballot: 2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) AB 2 ST

There were 64 sets of responses, including comments from approximately 162 different people from approximately 112 different companies representing 10 of the 10 Industry Segments as shown on the following pages.

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 the Director of Standards, Howard Gugel (via email) or at (404) 446-9693.

The drafting team made grammatical edits and provided additional information in the Rationale boxes and Supplemental Material section of the draft standard. The following clarifying revisions to the balloted standard were also made:

Requirements

Requirement R1, Part 1.1

Changed from "A review and update of short-circuit models for the BES Elements under study." to "A review and update of short-circuit model data for the BES Elements under study."

Requirement R1, Part 1.3.4

Changed the format incorporating the subparts into the main body of Part 1.3.4. It now reads as follows:

"Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure."

Requirement R2

Option 2 and **Footnote:** Inserted "BES" as a modifier of Element.

Option 3: Inserted "Use" at the beginning to align formatting with options 1 and 2.

Footnote: Inserted the following to clarify where Fault current baselines can be established:

"The Fault current baseline for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), or at the common point of connection at 100 kV or above. For dispersed power producing resources, the Fault current baseline may also be established at the BES aggregation point (total capacity greater than 75 MVA)."

Attachment A: Revised general language.

Implementation Plan

Effective Date of New or Revised Standards

Changed the implementation period of the standard from twelve (12) months to twenty-four (24) months to provide entities more time to establish the (1) Protection System settings development process, (2) Fault Current baselines, and (3) tracking tool(s) for Fault Current baseline changes and/or Protection System Coordination Studies.

Added section "**Initial Performance of Requirement R2**"

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with

Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Questions

1. **The term "entity-designated" and its associated footnote were removed and replaced by "Attachment A." Attachment A lists the Protection System functions applicable in the standard. Do you agree that Attachment A includes the Protection System functions that must be reviewed to maintain Protection System coordination when Fault current levels change? If not, please provide the basis for your disagreement and any proposed revisions.**

2. **Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.**

3. **If you have any other comments that you haven't already provided in response to the above questions, 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

1. The term "entity-designated" and its associated footnote were removed and replaced by "Attachment A." Attachment A lists the Protection System functions applicable in the standard. Do you agree that Attachment A includes the Protection System functions that must be reviewed to maintain Protection System coordination when Fault current levels change? If not, please provide the basis for your disagreement and any proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Selected Answer: Yes

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Selected Answer: No

Answer Comment:

• Attachment A does not list bus differential protection as an applicable protection function. Bus protection designed using either overcurrent, percentage differential or high impedance differential protection use a sum of currents to detect a bus fault. In an ideal world an increase in fault current would not affect the differential relays, but there are situations where an increase in fault current can negatively affect the differential relays and affect the coordination between bus differential and line relays.

◦ Overcurrent and percentage differential relays are usually applied on busses where fault currents are low enough so that CT saturation does not occur. As fault currents increase, the chances of CT saturation increase which can cause false bus differential operations for external line faults.

◦ High impedance differential relay voltage settings are calculated based on the voltage that could be developed across the relay with a completely saturated CT. This voltage setting is calculated using the maximum external fault current. With increased fault currents, the voltage that could develop across the relay for a saturated CT could be higher than the voltage setting of the relay. This can also cause false bus differential operations for external line faults.

Bus differential relays should be added to Attachment A to ensure that proper coordination between bus differential relays and line relays for external faults.

Response: Thank you for your comment. The drafting team asserts your examples represent local relay setting issues, not coordination issues. Bus differential relays settings are not based on coordination with other relays.

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

Selected Answer: Yes

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer: Yes

Thomas Foltz - AEP - 5 -

Selected Answer: Yes

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer: Yes

Mark Kenny - Northeast Utilities - 3 -

Selected Answer: Yes

Answer Comment: We agree with the classification of specific protection system elements that require coordination. In addition, this will aid the compliance enforcement process.

Response: Thank you for your comment.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer: Yes

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Selected Answer: Yes

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6

Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4
Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer: Yes

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5

Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer: Yes

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Jay Barnett - Exxon Mobil - 7 -

Selected Answer: Yes

Answer Comment:

While I agree that the functions listed are the ones that should be reviewed if fault current levels change, I disagree with using fault current as a trigger for a review *in all circumstances*. For those functions that do not require fault current or Protection System settings from other entities in order to ensure proper coordination, entities should be able to use equipment changes as a trigger for a coordination review. Equipment changes are already used as a trigger for other Reliability Standards and would allow for entities to have a single trigger for multiple Standards. This would add an additional, more cost effective option, while still ensuring Protection Systems on all BES Elements are coordinated. The SDT should include this as another option under Requirement 2 (see proposed revision below). A fault current trigger would remain for those functions that require fault current or Protection System settings from other entities in order to ensure proper coordination.

Proposed Revision:

R2. Each TO, GO, and DP shall, for each BES Element with Protection System functions identified in Attachment A:

Option 1: Perform a Protection System Coordination Study in a time interval not to exceed six calendar years; or

Option 2: . Compare present Fault current values to an established Fault current baseline and perform a Protection System Coordination Study when the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground) at a bus to which the Element is connected, all in a time interval not to exceed six calendar years; or,

Option 3: For functions that do not require Fault current or Protection System settings from other entities to ensure proper coordination, perform a PSCS prior to the implementation of new or modified Protection System settings on associated BES Elements.

Option 4: A combination of the above.

Response: Thank you for your comment. An entity must use at least one of the options provided in Requirement R2 to satisfy the requirement but the standard does not preclude an entity from performing additional Protection System Coordination Studies (PSCS) based on triggers other than Fault current or from performing PSCS more frequently.

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:	Yes	
Likes:	1	Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1, Ke
Dislikes:	0	

Earle Saunders - Edison International - Southern California Edison Company - 6 -

Selected Answer: Yes

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer: Yes

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

Selected Answer: No

Answer Comment: For the GO function, it would be helpful to include 51V-R and 51V-C as in scope relays in Attachment A. Also for GO, it would be helpful to note that 50/27 or 67 relays/protective functions used in generator inadvertent energization schemes are not in scope for PRC-027. Additionally, it's not clear if the 50 includes overcurrent elements used to supervise distance (21) elements.

Response: Thank you for your comment. Any variation of 51 time overcurrent relays are included in Attachment A. Unless the 50/27 and 67 Protection System functions are installed to detect and isolate Faults on BES Elements, the functions are not included in the Applicability of PRC-027. The Supplemental Material includes the following: A “50 – Instantaneous overcurrent” function used for supervising a “21 – Distance” function would not be included in a Protection System Coordination Study as it does not require coordination with other Protection Systems.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer: No

Answer Comment: Revision Requirement 1 allows us to develop a criteria for intended sequence which is good. Our only concern is if our criteria changes, there is no verbiage in the standard that allows for a phased implementation plan. One suggestion could be to give a 6 year cycle to be sure improvements are made will staying compliant to the proposed standard.

Response: Thank you for your comment. The process established in Requirement R1 is for developing new and revised Protection System settings for BES Elements. If an entity makes changes to its process, the entity will follow its new process to develop all future new or revised Protection System settings. There is no requirement that an entity retroactively implement its new process on previously developed Protection System settings.

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer: No

Answer Comment: See Comments from ACES

Response: Please see the drafting team's responses to the referenced comments.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer: Yes

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer: No

Answer Comment: In Attachment A, it seems that 67 elements used in communication-aided protection schemes should be applicable. If a communication-aided protecton scheme is needed for coordination with remote backup (e.g., long line adjacent to a short line, perhaps), a check may need to be performed that (for example) overreaching ground overcurrent pickups are still appropriate. Tacoma Power will not object to lowering the compliance risk by leaving these elements out of Attachment A, but Tacoma Power did want to bring this to the drafting team's attention.

In Attachment A, or in the Supplemental Material section, breaker failure fault detectors should be discussed. As with the 67 element, if a breaker failure fault detector is set too high in (for example) a ring bus, remote backup protection could operate instead of the local breaker failure. As with the 67 element, Tacoma Power will not object to lowering the compliance risk by leaving these elements out of Attachment A, but it probably should be at least discussed by the drafting team and documented somewhere to avoid confusion later when/after the standard becomes effective.

Response: Thank you for your comment. The protective functions listed in Attachment A are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the 67 element used in an overreaching communication scheme is not directly used to isolate Faults on BES Elements. With regards to breaker failure fault detectors, the drafting team does not consider your example a coordination issue but instead a local relay setting issue. Breaker failure Fault detector settings are not based on coordination with other relays.

Glenn Pressler - CPS Energy - 1 -

Selected Answer: No

Answer Comment: Agree with the elements listed, but I question the wording regarding the 21 elements. It sounds as if an entity simply sets this element by

	just taking a percent of the Positive Sequence Line impedance, even when infeed or mutuals are present (ground only), then the entity would never need to check these elements. However, if another entity does use these factors in determining settings of these elements, then that entity would be required to periodically check the settings. This seems to give a greater degree of risk for compliance failure for the entity that applies a more thorough method of setting these elements while leaving no risk to the entity that uses a simpler, less thorough setting method. Generally believe entities should be required to verify through studies that these elements will only operate for their intended zone of protection whenever infeed or mutuals are present.

Response: Thank you for your comment. The drafting team recognizes that entities have different protection philosophies to develop 21 element settings. If an entity does not consider infeed and no zero-sequence mutual impedances are present, the coordination of 21 elements would not need to be reviewed on a periodic basis because the settings are not based on available Fault current.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer: Yes

David Greene - SERC - 10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments

Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Selected Answer: Yes

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer: Yes

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2

Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Selected Answer: Yes

Answer Comment: We agree that the addition of Attachment A gives the industry guidance to some of the system functions and their applicable in this process especially, in reference to the calculation of the Fault current when conducting the Protection System Coordination Study (PSCS). Additionally, this helps the industry develop effective procedures that will increase the Reliability of the BES.

Response: Thank you for your comment.

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: Yes

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6

Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Selected Answer: Yes

Answer Comment:	We agree with the classification of specific Protection System components that require coordination. In addition, this will aid the compliance enforcement process. However, clarification is requested with regard to applicability of distance protection element. Does the standard apply to distance elements used solely for non-communication aided protection schemes (for example transfer trip, carrier systems) or for all distance element applications?

Response: Thank you for your comment. If infeed is not used in determining the settings of the 21 elements used in the communication-aided Protection System, then 21 elements would not be included in the Protection System Coordination Study because settings are not developed based on available Fault current. The Supplemental Material section provides additional information on this subject.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:	Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:	Yes

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3 Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:	No

Answer Comment: Hydro One Networks Inc. agrees with the NPCC on the classification of specific protection systems that would entail protection system coordination. However, Hydro One Networks Inc.. would like to ask for clarification within Attachment 1 whether distance (21) elements within communications aided protection schemes are subject to the requirements of this standard. This is because there were conflicting responses provided by the NERC SDT during the Q&A Session held on August 25th, and by NATF during the monthly meeting call on August 27th.

Response: Thank you for your comment. If infeed is not used in determining the settings of the 21 elements used in the communication-aided Protection System, then 21 elements would not be included in the Protection System Coordination Study because settings are not developed based on available Fault current. The Supplemental Material section provides additional information on this subject.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1

Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer: No

Answer Comment: Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Response: Thank you for your comment. The protective functions listed in Attachment A are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the functions listed in Attachment A and only those functions require review when available Fault current levels increase or decrease.

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer: No

Answer Comment: Attachment A would be a good list of items that must be reviewed if Fault current levels are expected to always increase, but not for any Fault current level change.

Response: Thank you for your comment. The protective functions listed in Attachment A are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the functions listed in Attachment A and only those functions require review when available Fault current levels increase or decrease.

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Selected Answer: Yes

Answer Comment: Note: CAISO is not a party to the submission of the comments below.

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

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer: No

Answer Comment: See Section 3 below

Response: Please see the drafting team's responses to the referenced comments.

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer: Yes

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer: No

Answer Comment: See general comments in #3

Response: Please see the drafting team's responses to the referenced comments.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Selected Answer: Yes

Answer Comment:

1. We agree with the removal of the term "entity-designated" and the addition of Attachment A to provide more clarity.

2. Note #2 in the attachment refers to additional details located in the

supplemental information section of the standard. Once the standard is approved by FERC, only the applicability section and the requirements (and attachments that are incorporated by reference) will be enforceable. If the drafting team acknowledges that additional details are necessary to fully explain the attachment, then those details should be added at this stage of the development process.

Response: Thank you for your comments. Note 2 does not indicate that additional details are necessary to understand Attachment A. Note 2 simply indicates that additional discussion is provided in the Supplemental Material section of the standard, just as additional discussion is provided for the requirements, etc.

2. Do you agree with the proposed Implementation Plan? If not, please provide the basis for your disagreement and your proposed revisions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment: yes

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

Selected Answer:

Answer Comment: Yes,

SCE&G agrees with the SERC PCS committee comments: "It is our understanding that the 6-year evaluation interval begins on the enforcement date, allowing up to 6 years to complete a full system analysis. However, with this not being explicitly stated in the technical basis or implementation plan, we would recommend including that distinction in some location. "

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System

Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Selected Answer:

Answer Comment: Yes

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment: AEP does not believe that 12 months is adequate for the Implementation Plan, and recommends that it be increased to 24 months, which we believe is more reasonable. The GO often relies on the TO to provide short-circuit studies, which increases the time necessary to establish the initial baseline.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Selected Answer:

Answer Comment: **The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months after regulatory approvals to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review**

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Mark Kenny - Northeast Utilities - 3 -

Selected Answer:

Answer Comment: We strongly believe that 12 months is an inadequate amount of time for an entity to develop a formal documented process, establish a Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review. We recommend that the Implementation Plan should be extended to 24 months.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its

Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Selected Answer:

Answer Comment: Regarding Implementation Plan: NIPSCO believes 12 month implementation plan is very challenging and inadequate. NIPSCO recommends 24 months for implementation plan to allow entities sufficient time to establish resources and derive processes.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6
Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6

Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Selected Answer:

Answer Comment: The Technical Basis or Implementation Plan does not include sufficient details describing the 6 year evaluation interval. It is our understanding that this 6 year evaluation interval begins on the enforcement date allowing up to 6 years for the system analysis to be completed but this is not specifically stated so we recommend additional reference details be included to explicitly describe the Implementation times.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment: Yes

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4

Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Selected Answer:

Answer Comment: Yes

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	**Entity**	**Region**	**Segments**
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5

Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Selected Answer:

Answer Comment: No. While not "per se" an Implementation Plan issue, R2 is unclear as to when the first Protection System Coordination Study must be performed for Attachment A devices under R2. See additional comments in #3 below.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Likes: 4

PSEG - Public Service Electric and Gas Co., 1, Smith Joseph
PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey
PSEG - PSEG Fossil LLC, 5, Kucey Tim
PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment: Yes.

1) For R2, if an entity decides to go with option 1, does it mean that the entity is not required to do a Protection System Coordination Study until 6 years from the effective date of the standard?

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Jay Barnett - Exxon Mobil - 7 -

Selected Answer:

Answer Comment: Agree.

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Selected Answer:

Answer Comment: Salt River Project (SRP) has reviewed the Attachment A and has concerns with verifying a Fault Current baseline as required in R3. As this standard is written, this baseline must be created prior to the effective date of the standard. We strongly believe that 12 months is an inadequate amount of time to develop a formal documented process, establish a Fault Current baseline for thousands of relays, and establish a tracking tool for those Fault Current baseline changes and/or periodic review. We request that there be at least a 24 month implementation plan.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1,
Ke

Dislikes: 0

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Selected Answer:

Answer Comment: More detail is needed regarding the implementation plan dates for each of the requirements. Also, required dates for R2 should address Options 1 and 2 individually.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

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

Selected Answer:

Answer Comment: No; it would be helpful if the Implementation Plan included information on what is required on the effective date of the standard. There is clarifying text on page 7 of the RSAW that states what is required by the effective date of the standard, this could be included in the Implementation Plan.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Jennifer Losacco - NextEra Energy - Florida Power and Light Co. - 1 - FRCC

Selected Answer:

Answer Comment: We do not agree with the proposed implementation plan. For larger entiites with assets in all regions, a 12-month implementation is a challenge. 24-months would be more appropriate without taking on risk.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

William Hutchison - Southern Illinois Power Cooperative - 1 -

Selected Answer:

Answer Comment: No, See comments from ACES

Response: Please see the drafting team’s responses to the referenced comments.

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Selected Answer:

Answer Comment: SMUD Supports Salt River Project comments.

Response: Please see the drafting team's responses to the referenced comments.

Meghan Ferguson - Meghan Ferguson On Behalf of: Michael Moltane, International Transmission Company Holdings Corporation, 1

Selected Answer:

Answer Comment: There are no possible answers listed on this question to choose from (see attached screenshot), however, ITC Holdings would select 'YES' as an answer to this question.

Response: Thank you for your support.

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Selected Answer:

Answer Comment: It appears that, where Option 2 is selected, only the Fault current baselines need to be established prior to the effective date, not (necessarily) any Protection System Coordination Studies. Is this the drafting team's intention?

Where Option 1 is selected, what is the implementation timeframe?

Response: Thank you for your comment. Yes, when Option 2 is selected, only the Fault current baselines must be established prior to the effective date of the standard. Requirement R2, Option 1 states that a Protection System Coordination Study must be performed in a time interval not to exceed six-calendar years (of the effective date of the standard).

Glenn Pressler - CPS Energy - 1 -

Selected Answer:

Answer Comment: yes, but no button.

Response: Thank you for your support.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Selected Answer:

Answer Comment: Yes

David Greene - SERC - 10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Selected Answer:

Answer Comment: It is our understanding that the 6-year evaluation interval begins on the enforcement date, allowing up to 6 years to complete a full system analysis. However, with this not being explicitly stated in the technical basis or implementation plan, we would recommend including that distinction in some location.

Response: Thank you for your comment. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments
Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Selected Answer:

Answer Comment:

Based on our concerns regarding R1, subpart 1.2, as outlined in question 3, Duke Energy cannot agree to the proposed Implementation Plan. If the standard were to be approved as written, the expectation to review the developed Protection System settings, depending on the level of detail expected for the review, would take a significant amount of time to achieve compliance. For larger entities, with a great deal of applicable relays, additional resources would most definitely be required, and time to acquire and train those resources would be necessary. We do not feel the 12 months is an adequate amount of time to achieve compliance with the standard as written.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2
Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5, 6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Answer Comment: We agree with the proposed Implementation Plan. In our opinion, the footnote provides the industry a clear and concise objective pertaining to both projects and their dependence on the success of the proposed retirement of PRC-001-1-1 (ii).

Response: Thank you for your support.

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment: Yes

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1

Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1
Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5

Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Selected Answer:

Answer Comment: Checked--No

As it stands now, entities will not have adequate time, within 12 months, to develop a process, establish Fault current baselines, and establish a tracking tool for Fault current baseline changes and/or periodic review. We recommend that the Implementation Plan be extended to 24 months.

We recommend the implementation plan include a statement clarifying the start date of the 6 year cycle that is described in Requirement R2. Is it the date the standard is effective, or the date the protection system was last reviewed prior to the effective date?

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

The date of the last Protection System review prior to the effective date of the standard is not relevant in considering the initial performance of Requirement R2. The six-year interval begins on the effective date of the standard. To provide additional clarity, the drafting team added the following to the Implementation Plan.

Initial Performance of Requirement R2

For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Selected Answer:

Answer Comment: Yes.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment: Texas RE agrees with the proposed Implement Plan.

Response: Thank you for your support.

Kenn Backholm - Snohomish County PUD No. 1 - 6 -

Selected Answer:

Answer Comment: Public Utility District No. 1 of Snohomish County supports Salt River Project comments.

Response: Please see the drafting team's responses to the referenced comments.

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Selected Answer:

Answer Comment: Hydro One Networks Inc. does not agree with the Implementation Plan as it is unreasonable to implement a process and establish a fault current baseline within 12 months. Further, the Implementation Plan of 12 months borders on the Long-term Planning horizon in requirement R1 itself. The NERC definition of a Long-term Planning horizon is "a planning horizon of one year or longer". Therefore, Hydro One Networks Inc. agrees with the NPCC, and recommends that the Implementation Plan be extended from 12 months to 24 months.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name: FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Selected Answer:

Answer Comment: Yes

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Selected Answer:

Answer Comment: Texas RE agrees with the proposed Implementation Plan.

Response: Thank you for your support.

Alex Chua - Pacific Gas and Electric Company - 5 -

Selected Answer:

Answer Comment: Abstain

Matt Culverhouse - City of Bartow, Florida - 3 -

Selected Answer:

Answer Comment: Yes

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments
Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2

Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Selected Answer:

Answer Comment: **NO.**

The Implementation Plan should be extended to 24 months. As it stands now, entities only have 12 months after regulatory approvals to develop a process, establish Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

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

Group Name: Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5

John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Selected Answer:

Answer Comment: Yes.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Selected Answer:

Answer Comment: SCL does not have issues with this aspect. However, other utilities have expressed a concern about needing more time so it may be worthwhile re-evaluating the scope for implementation plan.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment: Yes.

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Selected Answer:

Answer Comment: Yes we have no issues but we have heard others are concerned that they will need more time.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment: If a utility is in the position to leverage a tool such as CAPE or ASPEN to automate its settings review, then the proposed implementation plan seems feasible. If a utility does not have a software tool in place, then developing and tracking the settings review may require significant resources. This may actually detract from a utility's ability to create and review relay settings.

Response: Thank you for your comment. Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5, 6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3

Bill Hutchison	Southern Illinois Power Cooperative	SERC	1
John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Selected Answer:

Answer Comment: We agree with the implementation plan that both standards (PRC-027-1 and TOP-009-1) must reach industry consensus before they are presented to the NERC Board for adoption.

Response: Thank you for your support. The standards may be presented to the NERC BOT separately but NERC will submit the petitions for PRC-027-1 and TOP-009-1 to FERC together, requesting the full retirement of PRC-001-1(ii).

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Selected Answer:

Answer Comment: yes

3. If you have any other comments that you haven't already provided in response to the above questions, please provide them here.

John Fontenot - Bryan Texas Utilities - 1 -

Answer Comment: none

Angela Gaines - Portland General Electric Co. - 1,3,5,6 - WECC

Answer Comment: Portland General Electric Company (PGE) thanks you for the opportunity to comment on this standard. PGE's System Protection group finds the proposed standard to be generally acceptable. We would, however, request that the drafting team review part 2 of PRC-023-3 Attachment A and consider exclusion of the relay elements listed in 2.1 from the requirement of PRC-027.

Response: Thank you for your comment. The drafting team reviewed PRC-023-3, Attachment A, and sees no reliability benefit in making your suggested change. Depending upon an entity's protection philosophy, the relay elements excluded by Part 2.1 of PRC-023-3 Attachment A may or may not meet the criteria for inclusion in Attachment A of PRC-027-1. The protective functions listed in Attachment A of PRC-027-1 are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the functions listed in Attachment A and only those functions require review when available Fault current levels increase or decrease.

Eric Schwarzrock - Berkshire Hathaway - NV Energy - 5 -

Answer Comment: • Option 2 of R2 is meant to allow an entity to periodically check for a 15 percent of greater deviation in fault current. This option allows the entity to choose an interval of up to six calendar years to perform the fault current comparisons (this comes from the PRC-027-1 supplemental material). Option 2 is worded in a confusing manner so that the intent is not immediately clear without reading the supplemental material.

• Attachment A lists the protection system functions applicable to R2 including: 67 – AC directional overcurrent if used in a **non-communication-aided protection scheme**. This is probably ok if the fault current increases. If the fault current decreases, then any 67 relays used in a communication-aided protection scheme might not work correctly. If the 67 element were set to overreach the other end of the line for a POTT scheme (similar to using a zone 2 element in a POTT scheme) and the fault current decreased, it's possible that the 67 element might now see faults at a maximum distance less than the distance of the line. This would render the POTT scheme not as effective since the element used to trigger the scheme does not see the entire line.

Option 2 states that a protection coordination study should be performed when a 15 percent or greater deviation in fault current is identified. A 15 percent decrease in fault current should warrant a re-study of directional overcurrent elements used in communication aided protection scheme.

Response: Thank you for your comment. Option 2 of Requirement R2 requires that both the Fault current comparison and any resulting Protection System Coordination Study (from the identification of a 15% or greater deviation in Fault current) be performed within a maximum 6-calendar-year timeframe. The drafting team notes that the purpose of the Rationale boxes and Supplemental Material section is to provide additional guidance and rationale regarding the tenets of the basic requirements of the standard. Though the Rationale boxes move to the Supplemental Material section of the standard when it becomes effective, both of these informational pieces remain a permanent part of the standard for entities and auditors to reference. Further, the draft Reliability Standard Audit Worksheet (RSAW) for PRC-027-1 explains what evidence is required to demonstrate compliance with this requirement.

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

Answer Comment:	SCE&G agrees with the SERC PCS committee comments: " Comments: 1) page 4, Please revise the Purpose and Facilities to clarify the scope. a) Purpose: "To maintain the coordination of Protection Systems installed to protect detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults." b) Facilities: "Protection Systems installed to detect and isolate Faults on protect BES Elements." Also see comment #3 below. There are a large number of DP-TO interfaces and clarity on this interface is needed. 2) page 6 Rationale Option 2: augment 'Planners and Planning Coordinators' with 'Transmission Owner' so it reads "The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Owners, Transmission Planners, or Planning Coordinators." This makes it consistent with R1 1.1 itself, page 14 explanation. 3) page 13 DP Applicability is explained by 'A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.' A) In the vast majority of cases fault current contributions from DP networks are quite

weak, usually the last to trip, and insignificant to BES coordination. B) BES Phase 2 Definition excluded networks below 50kV and at the least this should be acknowledged here. C) PRC-027-1 Draft 6 Applicability language is consistent with the PRC-005-2 language, for which PRC-005-2 Supplement states: "'…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).' The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection System **protecting** that Element should then be included within this standard." D) Add language similar to B and C in the PRC-027-1 Supplemental Material.

4) page 17 second option: Please clarify the Fault current location for the 15% deviation trigger is the BES bus. This will help the GO and DP understand their responsibility. Please insert BES before Element in this sentence "The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which an a BES Element is connected. The drafting team intends for the 100kV or above BES bus to be the Fault current location."

Response: Thank you for your comment.

The drafting team contends that the acts described in the Purpose statement "…detect and isolate Faults on Bulk Electric System (BES) Elements…" are the same as providing protection for those Elements. The drafting team declines to make the suggested change. (a) The drafting team contends that the phrase provided in section 4.2. Facilities, "…detect and isolate Faults on Bulk Electric System (BES) Elements…" is the same as providing protection for those Elements. The drafting team declines to make the suggested change.

The drafting team contends that the phrase provided in section 4.2. Facilities, "…detect and isolate Faults on Bulk Electric System (BES) Elements…" is the same as providing protection for those Elements. The drafting team declines to make the suggested change.

The drafting team modified the Rationale box for Requirement R2 to include the Transmission Owner as you suggest.

Thank you for your comment. PRC-027-1 is consistent in its applicability to Protection Systems designed to detect (and isolate) Faults on BES Elements, and will, therefore follow with any definition of the Bulk Electric System as you suggest. Protection System Coordination is about isolating Faults in an intended sequence, not just about protecting Elements from Faults. PRC-027-1 will also follow with any definition of the Bulk Electric System.

The drafting team made the suggested change.

Gul Khan - Gul Khan On Behalf of: Rod Kinard, Oncor Electric Delivery, 1

Answer Comment: n/a

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment: AEP supports R1 & R3. AEP believes it is reasonable to have a process to develop Protection System settings for all BES elements, and to implement that process. AEP is willing to accept the inclusion of all BES protection systems in these requirements.

AEP does not support R2 as written in draft 6. AEP believes R2 should be limited to protection systems applied on BES Elements that electrically join Facilities owned by separate functional entities. It is reasonable to require a periodic review, as prescribed in R2, on protection systems applied to interconnecting elements, because an entity does not have knowledge of what changes are made by another entity that may affect protection system coordination.

AEP believes that R1 is sufficient to cover coordination of all internal protection systems. AEP has an existing process to review area coordination when system changes are made. All settings in the area that are affected by the change are reviewed and revised as necessary. Because of this process, it is not likely that any fault current comparisons would identify a 15% deviation at any buses. Thus, this requirement would become an administrative burden without any reliability benefit for internal protection systems.

AEP proposes that R2 be changed to read:
R2. Each Transmission Owner, Generator Owner, and Distribution Provider shall, for each BES Element that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers) with Protection System functions identified in Attachment A:

While AEP is supportive of the overall intent and direction of PRC-027-1, we have chosen to vote negative driven by our objections to R2, as stated above.

Response: Thank you for your comment. The drafting team asserts it is difficult to support the position that having a procedure to develop settings alone will achieve the purpose of PRC-027-1: "To **maintain** the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults." The intent of Requirement R2 is to prevent existing Protection Systems (where no system modifications have occurred) from becoming uncoordinated due to incremental changes in Fault current that have occurred over time.

Likes: 0

Dislikes: 0

Mark Wilson - Mark Wilson On Behalf of: Leonard Kula, Independent Electricity System Operator, 2

Answer Comment: the HIGH VRF for Requirement R3 seems too high since failing to meet R1 (to develop the process for developing new and revised Protection System settings for BES Elements) has a MEDIUM VRF; failing to utilize this process should not have a VF that's higher than not having the process in place to begin with.

Response: Thank you for your comment. The drafting team modeled the VRFs for Requirements 1 and 3 after other FERC-approved NERC Reliability Standards. The VRFs for the requirements that required establishing or developing processes were lower VRFs than those requirements mandating the implementation or utilization of the processes. Please refer to the Violation Risk Factor and Violation Severity Level Justification Document for PRC-027-1.

Mark Kenny - Northeast Utilities - 3 -

Answer Comment:

1. We suggest that the drafting team consider the potential overlap of PRC-027-1 R1.1.1 and MOD-032-1, R1 and provide necessary clarification in the Supplemental Material.

2. R2, Option 2 has two actions associated with it, both of which have to be completed in one timeframe. The two actions are the fault current comparison against the baseline and the performance of a Protection System Coordination Study if the fault current comparison exceeds 15% or greater deviation. It is recommended that under this option, if an entity identifies a 15% or greater deviation in fault current value at a bus, the entity is given a set amount of time

per element to complete a protection coordination study on all applicable elements at that bus.

Response: Thank you for your comments.

There is no overlap or conflict between PRC-027-1 Requirement R1, Part 1.1 and MOD-032-1, Requirement R1. Requirement R1 Part 1.1 of PRC-027-1 ensures that the short-circuit model data is reviewed for accuracy before being used to develop new or revised Protection System settings.

Option 2 of Requirement R2 is a Fault current based methodology for determining when a PSCS must be performed for Protection System functions listed in Attachment A. The second action you mention (performing a Protection System Coordination Study) is only required when a 15% or greater deviation from the established baseline fault current at the bus to which the Element is connected is identified. An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

Anthony Jablonski - ReliabilityFirst - 10 -

Answer Comment:

ReliabilityFirst agrees that PRC-027-1 helps to alleviate the risk of insufficient coordination of Protection Systems installed to detect Faults on BES Elements and isolate those faulted Elements (such that the Protection Systems operate in the intended sequence during Faults). ReliabilityFirst offers the following comments related to the term "coordination" for the Standard Drafting Team's consideration:

1. **ReliabilityFirst notes that the term "coordination" used in Requirement 1, Parts 1.3.2 and 1.3.3 is not defined within PRC-027-1 or the NERC Glossary Terms. This term is also used within a number of other Reliability Standards**

where it is likewise undefined. As a result, and according to FERC precedent, the dictionary definition of the term "coordination" will control. As a result, the term "coordination" could reasonably be interpreted to refer to either the setting of Protection Systems *or* to communications between entities.

To add clarity to PRC-027-1, ReliabilityFirst recommends replacing the term "coordination" with the term "Protection System Coordination." Listed below is ReliabilityFirst's proposed NERC Glossary definition of "Protection System Coordination" for the Standard Drafting Team's consideration:

Protection System Coordination - The setting of Protection Systems installed for the purpose of detecting and isolating Faults on BES Elements, such that the Protection Systems operate in a defined sequence in an effort to remove such Faults from the BES.

1. ReliabilityFirst recommends the following changes to Requirement 1, Parts 1.3.2 and 1.3.3 to incorporate this new definition of "Protection System Coordination" (highlighted in red below):

1.3.2. Respond to any owner(s) that provided its proposed Protection System settings pursuant to Requirement R1, Part 1.3.1 by identifying any Protection System Coordination Issue(s) or affirming that no Protection System Coordination issue(s) were identified.

1.3.3. Verify that identified Protection System Coordination issue(s) associated with the proposed Protection System settings for the associated BES Elements are addressed prior to implementation.

Response: Thank you for your comments.

The definition of the term Protection System Coordination Study in PRC-027-1 and its use throughout the standard is sufficient to eliminate any misunderstanding of the term coordination in Requirement R1, Parts 1.3.2 and 1.3.3. The Supplemental Material section also contains the description of the "coordination of protection" from the pending revision of IEEE Standard C37.113-1999 (Reaffirmed: 2004), Guide for Protective Relay Applications to Transmission Lines which provides further guidance regarding the term "coordination". The drafting team contends a new term "Protection System Coordination" is not warranted.

Joe O'Brien - NiSource - Northern Indiana Public Service Co. - 6 -

Answer Comment: Regarding R2: NIPSCO believes that measurement criteria M2 for Protection System Coordination Studies (PSCS) is not very clear. Standard needs to provide a clear direction as to what is considered an acceptable form of evidence for PSCS.

Response: Thank you for your comment.

The drafting team developed the definition of Protection System Coordination Study with a focus on producing results that achieve the purpose of PRC-027-1 (ensuring Protection Systems operate in the [entity's] intended sequence during Faults) without prescribing how the studies be performed, or how the results must be presented. Measure M2 states that documentation of the Protection System Coordination Study is acceptable evidence.

Louis Slade - Dominion - Dominion Resources, Inc. - 6 -

Group Name: Dominion

Group Member Name	Entity	Region	Segments
Randi Heise	NERC Compliance Policy	NPCC	5,6

Connie Lowe	NERC Compliance Policy	SERC	1,3,5,6
Louis Slade	NERC Compliance Policy	RFC	5,6
Chip Humphrey	Power Generation Compliance	SERC	5
Nancy Ashberry	Power Generation Compliance	RFC	5
Larry Nash	Electric Transmission Compliance	SERC	1,3
Candace L Marshall	Electric Transmission Compliance	SERC	1,3
Larry W Bateman	Transmission Compliance	SERC	1,3
Jeffrey N Bailey	Nuclear Compliance	SERC	5
Russell Deane	Nuclear Compliance	NPCC	5

Answer Comment: • Comments: Section R1.1: Consider adding additional clarity to the sub-requirement to limit the review to the modified BES Elements or BES Elements in the zone of protection. For example, the statement could be modified as follows: "A review and update of short circuit models for the modified BES Elements under study or BES Elements in the zone of protection." This limits the scope of the short circuit model review to just the elements being studied.

Response: Thank you for your comment. Requirement R1 mandates that an entity establish a process for developing new and revised Protection System settings for BES Elements. This process shall be used each time new or revised Protection System settings are developed. Requirement R1, Part 1.1 ensures that the model data is accurate for the System protected by the new or revised Protection Systems.

Kayleigh Wilkerson - Lincoln Electric System - 5 -

Answer Comment: LES suggests that the evidence required to meet R3 be limited and clearly defined. As currently drafted, the scope of potential evidence to demonstrate compliance with R3 would be difficult to anticipate and therefore unmanageable. Recommend the evidence be limited to entities providing short-circuit model updates (R1.1), Protection System setting reviews (R1.2), and Protection System setting coordination between owners for electrically-joined Facilities (R1.3).

LES recommends Option 2 of R2 be further clarified. It is not clear if a Protection System Coordination Study is required even if a fault current baseline hasn't deviated by 15% in 6 years. Additionally, it is also not clear what the scope of the Protection System Coordination Study is. To provide further clarity to R2 Option 2, LES suggests modifications similar to the following:

Compare present Fault current values to an established Fault current baseline in a time interval not to exceed six calendar years. A Protection System Coordination Study must be performed on the Elements connected to the bus where the comparison identifies a 15 percent or greater deviation in Fault current values (either three phase or phase to ground). This Protection System Coordination Study must be completed within one calendar year of the Fault current comparison. The Fault current baseline will be updated to the present Fault current values only on the Elements for which the Protection System Coordination Study was performed.

Additionally, LES recommends protection system functions that are only enabled when other relays or associated systems fail be excluded from the R2 (e.g., overcurrent elements that are only enabled during loss of potential conditions). We feel that these protection system functions are used only as a contingency and should not fall within scope of the standard.

Response: Thank you for your comment.

Measures provide examples of evidence that may be used by entities to demonstrate compliance with the applicable requirements. The only time the "scope" of evidence could be limited is when there is only one type of evidence that will suffice.

The drafting team contends that Requirement R2 is clear that a Protection System Coordination Study is only required *"…**when the comparison identifies a 15 percent or greater deviation in Fault current values**…"*, and that it is not necessary to state the opposite – that a PSCS is not required when a 15% deviation is not identified. Further, the draft Reliability Standard Audit Worksheet (RSAW) for PRC-027-1 explains what evidence is required to demonstrate compliance with this requirement.

The drafting team developed the definition of Protection System Coordination Study with a focus on producing results that achieve the purpose of PRC-027-1 (ensuring Protection Systems operate in the [entity's] intended sequence during Faults) without prescribing how the studies be performed, or how the results must be presented. The drafting team also recognizes that Protection System designs and philosophies vary amongst entities, and performing a coordination study is more of an art than an exact science.

The drafting team reviewed PRC-023-3, Attachment A, and sees no reliability benefit in making your suggested change. Depending upon an entity's protection philosophy, the relay elements excluded by Requirement R2, Part 2.1 of PRC-023-3 Attachment A may or may not meet the criteria for inclusion in Attachment A of PRC-027-1. The protective functions listed in Attachment A of PRC-027-1 are included based on meeting the following criteria: (1) available Fault current levels are used to develop settings, and (2) the functions require coordination with other Protection Systems. The drafting team contends that the functions listed in Attachment A and only those functions require review when available Fault current levels increase or decrease.

Jeremy Voll - Basin Electric Power Cooperative - 3 -

Answer Comment: The BEPC believes that the same applicability exclusion used for PRC-001-1.1 (ii) or PRC-005 should be applied to PRC-027. The key is coordination at the overall wind farm interface after the power has been aggregated. Without this exclusion, the burden of the standard outweighs any reliability benefits provided.

Response: Thank you for your comments.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

For Requirement R2, the drafting team added language to the footnote to explain that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), the common point of connection at 100 kV or above, and the BES aggregation point (total capacity greater than 75 MVA) for dispersed power producing resources.

Emily Rousseau - MRO - 1,2,3,4,5,6 - MRO

Group Name: MRO-NERC Standards Review Forum (NSRF)

Group Member Name	Entity	Region	Segments
Joe Depoorter	Madison Gas & Electric	MRO	3,4,5,6
Amy Casucelli	Xcel Energy	MRO	1,3,5,6
Chuck Lawrence	American Transmission Company	MRO	1
Chuck Wicklund	Otter Tail Power Company	MRO	1,3,5
Theresa Allard	Minnkota Power Cooperative, Inc	MRO	1,3,5,6
Dave Rudolph	Basin Electric Power Cooperative	MRO	1,3,5,6
Kayleigh Wilkerson	Lincoln Electric System	MRO	1,3,5,6
Jodi Jenson	Western Area Power Administration	MRO	1,6
Larry Heckert	Alliant Energy	MRO	4

Mahmood Safi	Omaha Public Utility District	MRO	1,3,5,6
Marie Knox	Midwest ISO Inc.	MRO	2
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Randi Nyholm	Minnesota Power	MRO	1,5
Scott Nickels	Rochester Public Utilities	MRO	4
Terry Harbour	MidAmerican Energy Company	MRO	1,3,5,6
Tom Breene	Wisconsin Public Service Corporation	MRO	3,4,5,6
Tony Eddleman	Nebraska Public Power District	MRO	1,3,5

Answer Comment:

The NSRF believes that the same applicability exclusion used for PRC-001-1.1 (ii) or PRC-005 should be applied to PRC-027. The key is coordination at the overall wind farm interface after the power has been aggregated. Without this exclusion, the burden of the standard outweighs any reliability benefits provided.

The DGR applicability exclusion from PRC-001-1.1 (ii) should be added to R2, R3 or to Attachment A. FERC would not let a current requirement go unaddressed. Similarly, the individual generator exclusion from PRC-001-1.1 (ii) cannot be ignored. As an example, the following could be added to either a requirement or Attachment A:

• Requirement R2 is not applicable to the individual generating units of dispersed power producing resources identified through Inclusion I4 of the Bulk Electric System definition.

The exclusion is required to address the blanket inclusion of individual wind turbines under the new Bulk Electric System (BES) definition Inclusion 4 (I4) and wording in Requirement 2 that states “each BES Element with Protection System functions identified in Attachment A" are to be addressed.

Another alternative is the NSRF recommends an Applicability statement such as (PRC-005-2i):

- 4.1.4 Protection Systems for the following BES generator Facilities for dispersed power producing resources identified through Inclusion I4 of the BES definition:
- 4.1.4.1 Protection Systems for Facilities used in aggregating dispersed BES generation from the point where those resources aggregate to greater than 75 MVA to a common point of connection at 100 kV or above.

The NSRF would like to see the words "NERC registered" added in front of the word "owner" to ensure that entities with multiple non-NERC joint owners avoid the unnecessary administrative burden of attempting to track entities with no NERC responsibilities. With PSE and possibly LSE deregistration, entities could be connected with non-NERC entities. The NERC paper process of exchanging information could become asymmetric as only one entity has legal requirements for actions and the other doesn't. Adding "NERC registered" should reduce unnecessary administration and create a symmetric or level set of requirements between affected entities.

In order to take advantage of Requirement R2-Option 2, a fault current baseline must be established prior to the effective date. This sets entities up for the potential to do a considerable amount of work based upon the expectation that nothing will change between the approval date and the effective date. Given the degree of change with PRC-005, there is certainly some amount of apprehension in this regard. A better method would be to allow the entity to establish the baseline within one year after the effective date or allow a phased-in approach.

There is no requirement ensuring the Transmission Owner will share the model database or Fault current study results to allow Generation Owners and Distribution Providers to complete R2 Option 1, 2 or 3. The applicability section recognizes that the TO's are the typical entity maintaining the system model for Fault studies. NSRF prefers previous draft versions that required the TO to conduct fault studies on all buses, make comparisons and notify other entities if the fault current changed.

The 6-year frequency requirement could be relaxed to be more consistent with other relay maintenance activities or there should be more justification provided for the additional cost of more frequent analysis.

Response: Thank you for your comments.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

For Requirement R2, the drafting team added language to the footnote to explain that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), the common point of connection at 100 kV or above, and the BES aggregation point (total capacity greater than 75 MVA) for dispersed power producing resources.

John Seelke - PSEG - 1,3,5,6 - NPCC,RFC

Group Name: PSEG

Group Member Name	Entity	Region	Segments
Joseph Smith	Public Service Electric and Gas	RFC	1
Jeffrey Mueller	Public Service Electric and Gas Co.	RFC	3
Tim Kucey	PSEG Fossil LLC	RFC	5
Karla Jara	PSEG Energy Resources & Trade LLC	RFC	6

Answer Comment:

We have separately submitted a Word redline with comments. However, PSEG's comments are summarized below. We would vote "Affirmative" if the SDT adopted the changes proposed in PSEG's redline.

• We propose that the SDT modify the definition of Protection System Coordination Study by limiting it to Protection Systems for BES Elements.

• We propose that the SDT add "Transmission Planner" to the Functional Entities in Section 4.1. This change is consistent with proposed changes to delete R1.1 and add R4 so that the Transmission Planner performs Fault current studies and makes them available to their TOs, GOs, and DPs in R4. As we note in the rationale for R4:

"Transmission Planners develop short circuit data bases per MOD-032-1 and utilize them in TPL-001-4 to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt. Since Transmission Planners develop and use short circuit databases, having other entities (TOs, GOs and DPs) use them could introduce errors. Therefore, Transmission Planners should be required to calculate all Fault current values for its busses (an initial baseline and subsequent periodic updates) and make those available to its Transmission Owners, Generator Owners, and Distribution

Providers."

• In R2, we eliminated the footnote in Option 2 because proposed R4 will result in an initial Fault current baseline established by the TP on or before the effective date of the standard. Given this, when would an entity's first PSCS need to be performed for its Attachment A devices under R2? For example, if Option 2 is selected, is the first PSCS required when the baseline fault current increases by 15 percent or greater?

• Other changes in language in R1, R2, and R3 are explained in comments in the redline.

Response: Thank you for your comments.

Thank you for your suggested revisions. The drafting team reviewed them and does not agree that they are necessary or that they provide additional clarity.

The SDT asserts that the Protection Systems referenced in the definition of a Protection System Coordination Study are those that are specified in the applicability which states: "Protection Systems installed to detect and isolate Faults on BES Elements."

The drafting team disagrees that Transmission Planners need to be added to the applicability of PRC-027-1. It is the owners' responsibility to obtain any information needed to fulfill their functional entity obligations.

That is correct. Requirement R2 states that a Protection System Coordination Study is required "…when the comparison identifies a 15 percent or greater deviation in Fault current values…"

Likes:	4	PSEG - Public Service Electric and Gas Co., 1, Smith Joseph PSEG - Public Service Electric and Gas Co., 3, Mueller Jeffrey PSEG - PSEG Fossil LLC, 5, Kucey Tim PSEG - PSEG Energy Resources and Trade LLC, 6, Jara Karla

Dislikes:	0

Maryclaire Yatsko - Seminole Electric Cooperative, Inc. - 1,3,4,5,6 - FRCC

Answer Comment:	(1) Please address each of our following comments as many of them were not addressed in the last ballot action. If these comments are not addressed, Seminole may revise its ballot vote from affirmative to negative upon the next ballot action. (2) This Standard references the terms “BES Elements.” In reviewing the NERC Glossary, there are many references to merely “Elements” without the preceding “BES” adjective, i.e., Remedial Action Scheme definition. What is the difference between “BES Elements” and “Elements” (without the BES)? Is the term “Element” without BES reference to elements that are non-BES, and if that is the case, does subpart “e.” of the RAS definition apply to non-BES Elements as there is no preceding “BES”? “BES Elements” and “Elements” are still both utilized in the Standard. Per discussions with the drafting team, it was stated that this is accidental and that there is no difference and that the team will clean these up to merely state “Elements” in the next version. (3) In R2, if a review was performed on March 1, 2017 and an entity had 6 calendar years in which to complete the review, is that 6 full calendar years? Meaning, would an entity not have to complete another review until December 31, 2023? Could you please include the above example, or an example akin to the above in the guidelines as we want to confirm we understand that 6 full calendar years are allowed, which means that more than 72 months between tests could be taken under certain timing circumstances?

(4) In R1 Part 1.5.3, this Requirement merely states that the coordination issues need to be “addressed” prior to implementation. We have two questions on this requirement, the first being that after reviewing the supplemental guidance material, that under certain circumstances, such as where additional system modifications are needed, that such modifications do not need to take place before the settings changes if the entity didn’t originally place those modifications into the scope of the settings changes project. Because the Requirement does not require the modifications to take place in any future time, can the drafting team describe in more detail how these issues are “addressed prior to implementation”? In discussions with the drafting team regarding what “addressed” means is that any coordination issues need to be agreed upon between the entities and the entities must agree to the implementation actions and a timeframe for implementation, and depending on the circumstances, “outstanding” updates can be implemented after implementation of proposed Protection System changes. Please confirm that this is correct.

(5) In the Supplemental Material section, there are references to the terms “BES Protection System” and “Protection System.” The Standard applies to “Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements.” For purposes of this Standard, is a BES Protection System a Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those faulted elements? There are still references to “BES Protection System” and “Protection System.” In discussions with the drafting team it was noted that all of these references were going to be cleaned up to merely state “Protection System”. Please confirm.

(6) In Requirement R1, is the 15% value 15.% with two significant figures in that if we have a deviation of 14.6% we need to perform an evaluation as it rounds up to 15% or are there more significant figures, i.e., 15.0%? This was discussed again with the drafting team that our comment wasn’t answered in the guidance,

but per a phone conversation it was stated that anything above 15.000000000 (infinity) is a violation. We'd prefer the NERC drafting teams begin honoring significant digits as it's not a difficult clarification and it makes compliance problematic because we can't tell if it's intentional or not when the drafting teams stop at a certain point. Therefore, this request is still out there, please place as many digits the team feels is significant as we will keep making this comment on every future drafted Standard, e.g., is 15.000% enough for the drafting team?

(7) In Requirement R2, if an entity uses the time based option and uses a recent short-circuit study for its baseline study, does the 6-year option 2 time frame start from the time of enforcement of the Standard or from the date the short-circuit study was finalized? The answer to this question does not appear to be in the Requirement. For Option 2, per our discussion, if a Protection System Coordination Study is performed today, the 6 year timeframe doesn't begin until the enforcement date of the Standard, correct? We are still somewhat unclear as to when the Fault current baseline comparison needs to be performed however. For example, does a Fault current baseline need to be performed every 6 years? There is some language in the Rationale box on this issue, but that language says "may" and not "shall" so it appears this isn't a requirement but merely a suggestion

(8) "Electrically joined Facilities" is not defined. Per past discussions, the intent appears to be to describe Facilities that are electrically joined AND are physically joined. Meaning, that if one Facility is 10 miles down the transmission line from another Facility, albeit "electrically joined" by electrons moving through both Facilities, the Facilities are not physically touching, and therefore, not covered by the intent of "electrically joined Facilities" under this Standard. Is this correct?

Response: Thank you for your comment.

Thank you for noting the inconsistency. The drafting team modified all references to Elements to include BES to clarify that the standard is only applicable to BES Elements.

Your understanding of the meaning of "calendar years" is correct. The drafting team included an example in the Supplemental Material.

If additional system modifications are needed, then "addressing prior to implementation" would mean it was discussed and an acceptable solution was agreed to by all parties. As noted in the Supplemental Material "There could be instances where coordination issues are identified and the entities agree not to mitigate all of the issues based on engineering judgment." Therefore, in some cases, there may be no implementation actions.

Thank you for noting the inconsistency. The drafting team removed the BES modifier of Protection Systems in the three locations it was referenced in the Supplemental Material.

The drafting team asserts that "15 percent or greater deviation" is clear and that it is not necessary to include significant digits.

The date of the last Protection System review prior to the effective date of the standard is not relevant in considering the initial performance of Requirement R2. The six-year interval begins on the effective date of the standard. The drafting team added the following to the Implementation Plan.

1) **Initial Performance of Requirement R2**
   For each option under Requirement R2, the six-calendar-year interval begins on the effective date of PRC-027-1. The initial Protection System Coordination Study(ies) for Option 1, and the Fault current comparison(s) and any Protection System Coordination Study(ies) required as a result of the Fault current comparison(s) in Option 2 must be completed in accordance with Requirement R2 no later than six-calendar years after the effective date of PRC-027-1. However, applicable entities using Option 2 for their initial performance of Requirement R2 must establish an initial Fault current baseline by the effective date of PRC-027-1.

If an entity initially intends to use Option 2 as a review method for those BES Elements with Protection System functions identified in Attachment A, Fault current baselines for those BES Elements must be established prior to the effective date of the standard. Once the baseline is established, an entity must compare the Fault current baseline to the present Fault current value at the bus under study at least once every six-calendar years. The Fault current baseline is only updated each time a Protection System

Coordination Study is performed. Please see the Supplemental Material section of the standard for further discussion and examples.

Requirement R1, Parts 1.3.1 and 1.3.4 use the term "electrically joined Facilities" and are referring to Requirement R1, Part 1.3 which uses the phrase: "For Protection System settings applied on BES Elements that electrically join Facilities..." The drafting team asserts that no definition is necessary. The Facilities do not have to be physically touching to be electrically joined by a BES Element.

Mike Smith - Manitoba Hydro - 1 -

Answer Comment:

1) Manitoba Hydro suggests that the title of this standard is changed from "Coordination of Protection Systems for Performance During Faults" to: "Protection System Coordination Performance During Faults"

2) For section 1.3.4.2, "Misoperation investigation" may be better replaced by "Protection System operation investigation"

3) For R2, there seems to be no incentive (nor requirement) for entities to go with option 2 since they still have to do this study within 6 years regardless the level of fault current changes anyway.

Response: Thank you for your comments.

The drafting team declines to make the two suggested changes.

For existing Protection Systems, Requirement R2, Option 2 provides the entity the option to perform a Fault current comparison once every six-calendar-years as a trigger to determine the need for a Protection System Coordination Study (PSCS). Until a 15 percent or greater deviation in Fault current is identified through the Fault current comparisons, no PSCS is required.

Jay Barnett - Exxon Mobil - 7 -

Answer Comment:

The Supplemental Material states, "The Transmission Owner, which is typically the entity maintaining the system model for Fault studies, will provide the Fault current availability upon request by the Distribution Provider or Generator Owner," however, there is nothing in the draft of PRC-027-1 that requires this and that would ensure this is done in a timely manner. This draft might introduce the circumstance where the GO has the responsibility to periodically compare data that the TO has and maintains. The Standard should require TOs to respond to GO requests for Fault current data in a timely manner so that the GO can perform coordination studies if necessary. Another approach would be to transfer the responsibility of performing the periodic comparisons to the TOs. If the fault current changed by 15%, then the TO would notify the affected GO so that a coordination study would be performed. The same issue would exist for small TOs that do not maintain wide-area system models.

Proposed Revision:

R2.1. Upon discovery of a change in Fault current of a BES Element owned by another GO, TO, or DP, each TO shall provide the updated Fault current values to the affected owners within 90 calendar days of discovery.

OR

R2.1. Each TO that maintains Fault current values for BES Elements owned by other GOs, TOs, or DPs, shall respond to requests for such information from the GO, TO, or DP within 90 calendar days.

Also, Requirement 3 should be limited to the attributes listed in Requirement 1 in order to have a clear and consistent measure for compliance. As written, auditors would have to become familiar with each entity's entire coordination process in order to determine compliance. Instead each entity should only have to demonstrate compliance with those attributes which the Standard Drafting Team has determined are "must have" to ensure proper coordination, as described in Requirement R1.

Proposed Revision:

R3. Each TO, GO, and DP shall utilize a process that contains the minimum attributes established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

Response: Thank you for your comments.

The drafting team disagrees that it is necessary to have a requirement that mandates the Transmission Owner share the model database or Fault current studies and declines to make the suggested change.

The drafting team contends that Requirement R3 is clear and declines to make the suggested change.

Joshua Andersen - Salt River Project - 1,3,5,6 - WECC

Answer Comment:

Salt River Project (SRP) has concern over R1 part 1.1 and 1.2. As written, R1 calls for a "process for developing new and revised Protection System settings". Parts 1.1 and 1.2 requires a "review and update of short-circuit models" and a "review of the developed Protection System settings", respectively. The process defined in R1 should not have to include either review. SRP recommends changing part 1.1 and 1.2 to reflect "A methodology to evaluate ...". In previous conversations with the SDT NERC staffer, it was communicated that the intent of this requirement was to include a methodology, however the previous draft removed the language that would have signified a methodology was required. If the intent is that a process rather than the actual review is included, it should read as such.

Response: Thank you for your comment. The drafting team intends that the established process include provisions for the reviews described in Requirement R1, Parts 1.1 and 1.2. The provisions for the reviews can certainly describe an entity's methodology for achieving the reviews.

Likes: 1 Tarantino Joe On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1,
Ke

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Group Name: Exelon Utilities

Group Member Name	Entity	Region	Segments
Chris Scanlon	BGE, ComEd, PECO TO's	RFC	1
John Bee	BGE, ComEd, PECO LSE's	RFC	3

Answer Comment: The applicability of the standard needs to be clarified so that dispersed resources at the individual resource prior to the point of aggregation are not subject to the standards requirements. In the transition from PRC-001.1ii., the exclusion for dispersed resources appears to have been improperly dropped from PRC-027-1. The PRC-027-1 mapping document lists PRC-001.1ii R3.1 and the dispersed resources sub-bullet exclusion but we cannot find a record indicating that there was discussion resulting in a deliberate intent to remove the exclusion in the transition from PRC-001.1ii to PRC-027-1. While a change to applicability prior to a final ballot is considered a substantive change in Section 4.14 of Standards Process Manual, we note that per the same section, "Where there is a question as to whether a proposed modification is "substantive," the Standards Committee shall make the final determination". We therefore request that the SDT bring this issue to the Standards Committee for consideration and include the dispersed generation exclusion in PRC-001.1ii in PRC-027-1 prior to final ballot.

Other options to address this concern could include, clarification in the Supplementary Material section, notes to auditors in the RSAW or the submission by the SDT of a SAR to change the applicability consistent with the dispersed generator exclusion as currently included in PRC-001-1ii .

Response: Thank you for your comments.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

For Requirement R2, the drafting team added language to the footnote to explain that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), the common point of connection at 100 kV or above, and the BES aggregation point (total capacity greater than 75 MVA) for dispersed power producing resources.

The drafting team provided this same information in the Rationale box, the Supplemental Material, and the RSAW.

Barbara Kedrowski - WEC Energy Group, Inc. - 3,4,5,6 - RFC

Answer Comment: We would like to see an exception for distributed resources similar to what project 2014-01 is working on for other standards. Typically distributed resources do not look out to the transmission system, but unless they are excluded this will need to be examined and documented.

Response: Thank you for your comments.

The exclusion in PRC-001-1.1(ii), Requirement R3, R3.1 for dispersed power producing resources applies only to interconnections between different functional entities. As such, the exclusion only maps to Requirement R1, Part 1.3 in PRC-027-1. Due to the design of dispersed generation sites, the Protection Systems applied on the individual dispersed generation resources are not electrically joined Facilities owned by separate functional entities as specified in Requirement R1, Part 1.3 nor are they connected by BES Elements. Therefore Requirement R1, Part 1.3 does not apply to the Protection Systems applied on the individual dispersed generation resources. Requirement R1, Part 1.3 applies only to the Protection Systems applied on the BES Elements that electrically join Facilities owned by separate functional entities.

For Requirement R2, the drafting team added language to the footnote to explain that Fault current baselines for BES generating resources may be established at the generator, the generator step-up (GSU) transformer(s), the common point of connection at 100 kV or above, and the BES aggregation point (total capacity greater than 75 MVA) for dispersed power producing resources.

Spencer Tacke - Modesto Irrigation District - 4 -

Answer Comment: Hi,

I really believe the time period options for doing a Protection Coordination Study specified in R2 (Option 1 or Option 2) are much too large. When I used to attend the WECC Meetings on a regular basis, I remember how a high percentage of the major system outages were tied to mis-coordination or mis-operation of the protective relay systems of the various neighboring utilities. As the member's protection systems are critical to the reasonable reliability of the interconnected system, waiting six years to do another fault current check for the 15% threshold is unreasonable, or allowing no threshold current check but with a fixed 6 year time period between coordination studies, is asking for trouble. I would strongly support a one year period as the required time to do a new Protection System Coordination Study for each member's BES. Remember, NERC requires annual Transmission Planning Assessments (TPL Standards), so we should not accept any lower of a standard for a Protection System Coordination Study. Thank you.

Sincerely,

Spencer Tacke
Senior Electrical Engineer
Modesto Irrigation District
209-526-7414
spencert@mid.org.

Response: Thank you for your comment. Six-calendar years is the maximum period allowed by the standard. The standard does not preclude an entity from performing Protection System Coordination Studies more frequently, if desired.

Jeffrey DePriest - DTE Energy - Detroit Edison Company - 5 -

Answer Comment: It appears that if Option 1 is selected for R2, an entity has six years from the effective date to complete the study and also evidence for R3 would not be required until this same date. Please confirm.

Functional Entities, under Applicability and each requirement, should include Transmission Planners.

Response: Thank you for your comments.

Your understanding of Requirement R2, Option 1 is correct; however, evidence for Requirement R3 would be required if any new or revised Protection System settings were developed any time after the effective date of the standard.

The drafting team disagrees that Transmission Planners need to be added to the applicability of PRC-027-1. It is the owners' responsibility to obtain any information needed to fulfill their functional entity obligations.

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

Answer Comment:

Option 2 of R2 is meant to allow an entity to periodically check for a 15 percent of greater deviation in fault current. This option allows the entity to choose an interval of up to six calendar years to perform the fault current comparisons (this is derived from the PRC-027-1 supplemental material). The intent of Option 2 is not immediately clear without reading supplemental material. Given that compliance is measured only by the text of the requirement, R2 Option 2 should be clarified to indicate that if the 15 percent fault current baseline hasn't been exceeded, a protection coordination study isn't required even it if has been more than six calendar years. Or is the intent of the drafting team to state that if the 15 percent baseline threshold hasn't been exceeded a coordination study isn't required?

Additionally, the evidence retention section would benefit from clarification. There could be possible confusion with the 6 year interval of the standard versus a possible audit interval of 3 years.

Another opportunity for improvement would be to align the intervals with the intervals identified in PRC-019, which would be beneficial to GOs.

Response: Thank you for your comment.

The drafting team notes that the purpose of the Rationale boxes and Supplemental Material section is to provide additional guidance and rationale regarding the tenets of the basic requirements of the standard. Though the Rationale boxes move to the Supplemental Material section of the standard when it becomes effective, both of these informational pieces remain a permanent part of the standard for entities and auditors to reference. Further, the draft Reliability Standard Audit Worksheet (RSAW) for PRC-027-1 makes clear what evidence is required to demonstrate compliance with this requirement.

The drafting team contends that Requirement R2 is clear that a Protection System Coordination Study (PSCS) is only required *"…**when the comparison identifies a 15 percent or greater deviation in Fault current values**…"*, and that it is not necessary to state the opposite – that a PSCS is not required when a 15% deviation is not identified.

The drafting team asserts that the evidence retention section is clear and no clarification is needed.

The drafting team does not see any benefit in aligning the intervals of the two standards. PRC-027-1 does not preclude an entity from using a shorter time period than the six-calendar-years specified in Requirement R2.

William Hutchison - Southern Illinois Power Cooperative - 1 -

Answer Comment: See Comments from ACES

Response: Please see the drafting team's responses to the referenced comments.

Joe Tarantino - Joe Tarantino On Behalf of: Diane Clark, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Kevin Smith, Balancing Authority of Northern California, 1
Michael Ramirez, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Rachel Moore, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Susan Gill-Zobitz, Sacramento Municipal Utility District, 3, 4, 6, 5, 1
Tim Kelley, Sacramento Municipal Utility District, 3, 4, 6, 5, 1

Answer Comment: SMUD supports Salt River Project comments.

Response: Please see the drafting team's responses to the referenced comments.

John Merrell - Tacoma Public Utilities (Tacoma, WA) - 1 -

Answer Comment: In the Supplemental Material section, there are concerns about the following paragraph: "A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider." If the generator is not a BES generator, or the generation plant is not a BES plant, the associated Protection Systems should not be under the purview of this standard unless, perhaps, they serve to provide a blocking signal to other Protection Systems associated with the BES Element or their clearing is necessary for the other Protection Systems associated with the BES Element to operate properly. For small non-BES generation, the Transmission Owner may configure its Protection Systems to properly respond with or without the small generator(s) connected. In these cases, clearing the generator(s) is arguably more about safety (isolating sources of energization) and not coordination.

It sounds like the only triggers for conducting a Protection System Coordination Study (PSCS) are the following: (1) triggered by Requirement R2, (2) triggered by the need to establish a baseline for Requirement R2 for new BES Elements or new BES Facilities, or (3) triggered by the need to establish a baseline for Requirement R2 when transitioning between Options 1 and 2. Otherwise, if there are Protection System changes, or if there are changes to existing BES Elements, it sounds like a PSCS is not (necessarily) required, provided that the other elements identified in Requirement R1 are addressed. Is this the drafting team's intention? If a PSCS will be required for other cases, this should be more clearly identified.

The verbiage in Requirement R2, Option 2, is a little unclear. For example, if Fault current values are compared within four calendar years, and the percentage change is less than 15%, does this reset the maximum six calendar year interval under Option 2?

Under Requirement R1, Part 1.3.4, Tacoma Power suggests appending "…scenarios such as the following:"

The Rationale for Requirement R1 includes a note about internal documentation. Tacoma Power had hoped that documentation would not explicitly be required in a scenario in which one engineering workgroup is responsible for Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities, especially when those functional entities are part of the same company/organization. There is concern about the amount of extra documentation that may be involved. Furthermore, when different functional entities are part of the same company/organization, it may not be 100% clear where the DP vs. TO or TO vs. GO line should be drawn; by contrast, the same internal documentation would not be required for internal TO-TO interaction.

The emphasis of this standard should only be to show that there is not miscoordination. It is a little awkward, but Tacoma Power suggests that the Purpose statement could be reworded to the following (CAPS added to identify suggested rewording): "To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems DO NOT operate in the UNintended sequence during Faults." Similarly, the definition of a PSCS could be reworded to the following: "An analysis to determine whether Protection Systems DO NOT operate in the UNintended sequence during Faults." Requirement R1 could be reworded to the following: "...such that the Protection Systems DO NOT operate in the UNintended sequence during Faults..."

Compared to Requirement R1, Tacoma Power is not convinced that the justification has been made for a High VRF for Requirement R3. Failing to implement one piece of the process established under Requirement R1, even for one BES Element, coupled with no graduated VSLs (see subsequent comment), would result in the maximum potential penalty.

Tacoma Power believes that the drafting team should leverage the Lower, Moderate, and High VSLs for Requriement R3. FERC's VSL G1 only states that the VSL assignment should not have the UNINTENDED consequence of lowering the current level of compliance. Furthermore, the scope of applicability of PRC-027-1 is much greater than PRC-001-1, so it is reasonable for PRC-027-1 to leverage the Lower, Moderate, and High VSLs, even though PRC-001-1 did not.

An example of a Protection System Coordination Study in the Supplemental Material section might be helpful.

Response: Thank you for your comments.

If the Distribution Provider that provides the path to the BES of a non-BES generator installs Protection Systems to detect and isolate Faults on BES Elements, then those Protection Systems would be applicable to PRC-027-1.
A Protection System Coordination Study is only required to be performed in Requirement R2.

Performance of the Fault current comparison, as provided in your example, would reset the clock for the six-calendar-year, maximum interval. Please see the example provided in the Supplemental Material section of the standard.

The drafting team declines to make the suggested change.

The note "In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation." is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. If an entity has a single group performing its coordination work for separate functional entities within an organization, it should make that declaration in its process.

The drafting team contends that maintaining the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults, as stated in the Purpose of PRC-027-1, achieves the same objective as ensuring the negative does not occur (that they do not operate in an unintended sequence). It is the drafting team's position that ensuring coordination is maintained requires less effort than proving that miscoordination does not exist.

Regarding Requirement R3, the drafting team disagrees and asserts that an entity is either utilizing its process or not.
The drafting team contends that failure to implement Requirement R1 could have an adverse effect on the reliability of the Bulk Electric System and, therefore, the High VRF for Requirement R3 is justified.

The drafting team did not provide an example of a Protection System Coordination Study because there are many different forms entities could use to develop their settings and verify coordination.

Glenn Pressler - CPS Energy - 1 -

Answer Comment:

R1 – Generally think there should be a bit more detail or definiation provided to "Protection System settings" that require reviewing. Does this just include element set values? Or does it also include logic settings? Drawings versus output contact programming? What about communications equipment? Keeping this wide open and letting entities define goes back down the PRC-005-1 road where some entities had much higher testing and maintenance standards, but were also held to that higher standard and punished harshly when even falling just short.

R2 – Generally believe that giving the option of using fault studies or a time interval is for determining when to review coordination in R2. However, believe that if using the baseline fault studies, then the entity should have a shorter period between performing such studies. One issues with the baseline fault studies is that coordination studies may go for an additional 6 years, even if the 6 year study shows the fault current at just below the 15% threshold. I believe a 3 year or 4 year interval would be more reasonable. Otherwise, why not just use the baseline method since it too is on a 6 year interval.

Response: Thank you for your comment.

The drafting team disagrees that more detail is necessary. The Protection System settings that require reviewing are those that ensure the Protection Systems operate in the intended sequence during Faults.

Six-calendar-years is the maximum period allowed by the standard. The standard does not preclude an entity from performing Protection System Coordination Studies more frequently, if desired.

Erika Doot - U.S. Bureau of Reclamation - 5 -

Answer Comment:

Reclamation suggests that the drafting team reorder R2 and R3 for clarity. This would allow the standard to follow a logical order requiring an entity to have a system protection coordination process (R1), follow it (R2), and periodically update system protection coordination studies for functions in Attachment A (R3).

Reclamation also suggests that the drafting team update R1.3.4 to clarify that communications resulting from unforeseen circumstances may be “after-the-fact notifications” rather than requiring advance communication. This would clarify that Protection System owners do not need to wait for confirmation from owners of electrically-joined Facilities before revising Protection System settings due to unforeseen circumstances. Reclamation believes that waiting for coordination with owners of electrically joined facilities in these situations could increase risks to BES reliability from faulty Protection System settings that are discovered during commissioning, misoperation investigations, and maintenance or component failures which should be addressed immediately. Reclamation suggests that this should be clear in the requirement itself, not merely mentioned in the supplemental material.

Finally, Reclamation suggests that the drafting team update M3 to provide examples of how an entity would demonstrate that it is following the process required by R1 to include more detail regarding example evidence to show compliance with each subrequirement.

Response: Thank you for your comments.
The drafting team declines to make the suggested change. If a Protection System Coordination Study performed in accordance with Requirement R2 identifies revised settings are necessary, an entity will use its process (Requirement R3) to develop those settings.

The drafting team disagrees that further clarification is necessary regarding Part 1.3.4. As written, the drafting team contends the intent is clear that an entity may notify the other entities after any Protection System settings are revised resulting from the unforeseen circumstances.

The drafting team asserts that the evidence an entity will need to demonstrate compliance with its process will be dependent upon its process, and because every entity's process for developing settings could be different, the drafting team declines to make the suggested changes to Measure M3.

David Greene - SERC - 10 - SERC

Group Name: SERC PCS

Group Member Name	Entity	Region	Segments
Paul Nauert	Ameren	SERC	1
Charlie Fink	Entergy	SERC	1
David Greene	SERC staff	SERC	10

Answer Comment:

1) page 4, Please revise the Purpose and Facilities to clarify the scope.
a) Purpose: "To maintain the coordination of Protection Systems installed to protect Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults."
b) Facilities: "Protection Systems installed to protect BES Elements."

Also see comment #3 below. There are a large number of DP-TO interfaces and clarity on this interface is needed.

2) page 6 Rationale Option 2: augment 'Planners and Planning Coordinators' with

‘Transmission Owner’ so it reads “The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Owners, Transmission Planners, or Planning Coordinators.” This makes it consistent with R1 1.1 itself, page 14 explanation.

3) page 13 DP Applicability is explained by ‘A Distribution Provider may provide an electrical interconnection and path to the BES for generators that will contribute current to Faults that occur on the BES. If the Distribution Provider owns Protection Systems that operate for those Faults, it is important that those Protection Systems are coordinated with other Protection Systems that can be impacted by the current contribution to the Fault of Distribution Provider.’ A) In the vast majority of cases fault current contributions from DP networks are quite weak, usually the last to trip, and insignificant to BES coordination. B) BES Phase 2 Definition excluded networks below 50kV and at the least this should be acknowledged here. C) PRC-027-1 Draft 6 Applicability language is consistent with the PRC-005-2 language, for which PRC-005-2 Supplement states: “‘…that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).’ The drafting team intends that this standard will follow with any definition of the Bulk Electric System. There should be no ambiguity; if the Element is a BES Element, then the Protection
System protecting that Element should then be included within this standard." D) Add language similar to B and C in the PRC-027-1 Supplemental Material.

4) page 17 second option: Please clarify the Fault current location for the 15% deviation trigger is the BES bus. This will help the GO and DP understand their responsibility. Please insert BES before Element in this sentence “The second option allows the entity to periodically check for a 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground) from an established Fault current baseline for Protection Systems at each bus to which a BES Element is connected. The drafting team intends for the 100kV or above BES

bus
to be the Fault current location."

Response: Thank you for your comments.

The drafting team contends that the acts described in the Purpose statement "…detect and isolate Faults on Bulk Electric System (BES) Elements…" are the same as providing protection for those Elements. The drafting team declines to make the suggested change. (a) The drafting team contends that the phrase provided in section 4.2. Facilities, "…detect and isolate Faults on Bulk Electric System (BES) Elements…" is the same as providing protection for those Elements. The drafting team declines to make the suggested change.

The drafting team contends that the phrase provided in section 4.2. Facilities, "…detect and isolate Faults on Bulk Electric System (BES) Elements…" is the same as providing protection for those Elements. The drafting team declines to make the suggested change.

The drafting team modified the Rationale box for Requirement R2 to include the Transmission Owner as you suggest.

Thank you for your comment. PRC-027-1 is consistent in its applicability to Protection Systems designed to detect (and isolate) Faults on BES Elements, and will, therefore follow with any definition of the Bulk Electric System as you suggest. Protection System Coordination is about isolating Faults in an intended sequence, not just about protecting Elements from Faults. PRC-027-1 will also follow with any definition of the Bulk Electric System.

The drafting team made the suggested change.

Colby Bellville - Duke Energy - 1,3,5,6 - FRCC,SERC,RFC

Group Name: Duke Energy

Group Member Name	Entity	Region	Segments

Doug Hils	Duke Energy	RFC	1
Lee Schuster	Duke Energy	FRCC	3
Dale Goodwine	Duke Energy	SERC	5
Greg Cecil	Duke Energy	RFC	6

Answer Comment:

Upon our review of the most recent draft of the proposed PRC-027-1 standard, we have significant concerns regarding the expectations outlined in R1, subpart 1.2. In part 1.2, the applicable Functional Entity is required to conduct or ensure some type of review is done on its Protection System settings. While the latitude that is given to the industry on how and what type of review they are to implement is recognized, we feel that specifically mandating a quality review is unnecessary. The requirement of ensuring that quality reviews are executed is not currently included in other Protection and Control standards, and is not mandated in other standard families (with the exception of CIP-014). We do not disagree with the practice of quality assurance, however, we do not support the practice of requiring an entity to do so in a Reliability Standard. Duke Energy recommends the removal of subpart 1.2 from R1.

Response: Thank you for your comment. The drafting team asserts that Requirement R1, Part 1.2 is an essential part of the settings development process and declines to make the suggested change.

Shannon Mickens - Southwest Power Pool, Inc. (RTO) - 2 - SPP

Group Name: SPP Standards Review Group

Group Member Name	Entity	Region	Segments
Shannon Mickens	Southwest Power Pool Inc.	SPP	2

Jason Smith	Southwest Power Pool Inc	SPP	2
Jonathan Hayes	Southwest Power Pool Inc	SPP	2
Robert Gray	Board of Public Utilities of Kansas City, Kansas	SPP	3
Michael Jacobs	Camstex	NA - Not Applicable	NA - Not Applicable
stephanie Johnson	Westar Energy, Inc	SPP	1,3,5,6
Mike Kidwell	Empire District Electric Company	SPP	1,3,5
James Nail	City of Independence, Missouri	SPP	3,5

Answer Comment: We have a concern about the mentioning of the Transmission Planner and Planning Coordinator in the Requirement R2 Rationale Box and those entities performing the calculations for the Fault current through short circuit analysis. The Rationale Box for Requirement R2 states "The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators". We would suggest the removal of those entities from the Rationale Box because they aren't include in the applicability section of the standard. Additionally, we feel that the fault current calculation has been addressed in the scope of the TPL Documentation. In that documentation, it is understood that the Transmission Planner or Planning Coordinator will conduct the fault current analysis on the BES facilities however, the Transmission Planner would have to coordinate with the owners and determine which protection systems would be impacted.

Response: Thank you for your comment. The drafting team notes that the purpose of the Rationale boxes and Supplemental Material section is to provide additional guidance and rationale regarding the tenets of the basic requirements of the standard. Though the Rationale boxes move to the Supplemental Material section of the standard when it becomes effective, both of these informational pieces remain a permanent part of the standard for entities and auditors to reference. Further, the draft Reliability Standard Audit Worksheet (RSAW) for PRC-027-1 explains what evidence is required to demonstrate compliance with this requirement. The drafting team declines to make the suggested change but did add the Transmission Owner as another source for Fault current values.

Gerry Adamski - Essential Power, LLC - 5 -

Answer Comment:

I believe it would be appropriate to include the Transmission Planner as an applicable entity for R2 purposes as they typically maintain the fault current/short circuit values at the buses.

I had to reread R2 a couple of times to be clear that the coordination study required as part of Option 2 only applies to the buses where the deviation exceeds 15% and not required of all the buses. If an opportunity exists, a minor clarifying edit would be recommended.

in R2, the standard speaks to a deviation at a bus to which the Element is connected. Is this intended to be a bus that is part of the BES? I'm thinking of how this would be applied at a generating plant where there is the transmission voltage level bus, the generating plant bus (e.g. 18 kV), lower voltage level buses within the plant, etc. I'm wondering how this aspect would be applied in practice at a plant. Perhaps clarifying edits in the requirement language and accompanying discourse in the rationale would help clarify this…

Response: Thank you for your comments.

The drafting team disagrees that Transmission Planners need to be added to the applicability of PRC-027-1. It is the owners' responsibility to obtain any information needed to fulfill their functional entity obligations.

As written, Option 2 specifies the performance of a Protection System Coordination Study is only required *"…when the comparison identifies a 15 percent or greater deviation in Fault current values…**at a bus to which the Element is connected**…"* Please reference the Rationale box and Supplemental Material sections of the standard for further discussion and examples associated with Requirement R2.

The Applicability section, Part 4.2. Facilities of PRC-027-1 limits the requirements of PRC-027-1 to Protection Systems installed to detect and isolate Faults on BES Elements. To address your concern, the drafting team clarified the language of Option 2 by adding the BES descriptor to modify Element. The Rationale and Supplemental Material sections also reflect this revision.

Louis Guidry - Louis Guidry On Behalf of: John Lindsey, Cleco Corporation, 6, 5, 3, 1
Michelle Corley, Cleco Corporation, 6, 5, 3, 1
Robert Hirchak, Cleco Corporation, 6, 5, 3, 1
Stephanie Huffman, Cleco Corporation, 6, 5, 3, 1

Answer Comment:

The definition of Power System Coordination Study is defined as an analysis of the operating sequence. Our interpretation of the definition is that we have to model the relay action and demonstrate that it operates in the intended sequence. Cleco uses fault simulations to develop the settings. We do not model the relays in our short-circuit program to demonstrate the relay action.

2. The standard requires an internal review of the developed settings. Who is going to review the settings currently develop? Relay settings are an art due to the compromised required because of so many unique problems. No two people are going to solve the problem exactly the same. Should two people develop the settings and compare results?

3. The standard requires a review of the short-circuit model prior to developing settings. What constitutes a valid review?

4. Requirement 1.3 says we get a response from other owners prior to implementing settings on associated BES elements. How much time before Cleco responds is required? How much time do we have to wait for a response? What if neighboring entity request a response for many of our associated systems at once?

Response: Thank you for your comments.

The drafting team chose not to be prescriptive in defining a Protection System Coordination Study. The method to perform the analysis to determine whether the Protection Systems operate in the intended sequence during Faults is left to the individual entity's discretion.

A review of the developed Protection System settings reduces the likelihood of introducing human error and verifies that the settings produced meet the technical criteria of the entity. Peer reviews, automated checking programs, and entity-developed review procedures are all examples of reviews.

A valid review would be one that ensures that the information in the short-circuit model accurately reflects the physical power system that will form the basis of the Protection System Coordination Study and development of Protection System relay settings.

The drafting team provided flexibility for entities to establish processes that best work for their protection philosophies and business practices. Communication with neighboring entities is required for certain provisions within the process; the drafting team asserts that entities will collaborate on schedules to ensure both parties' needs are met.

Jamison Cawley - Nebraska Public Power District - 1 -

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states “Fault current values (either three phase or phase to ground) at a bus to which the Element is connected” where the RSAW states “Fault current comparison and results for each BES Element”. The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified.

Please provide a definition or examples to clarify what is considered “electrically-joined Facilities”. For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 “electrically-joined”?

The RSAW in the sections for R1 and R3 states: “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation”. We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required.

In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance?

For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Response: Thank you for your comments.

The drafting team asserts that Requirement R2 and the footnote clearly indicate when a Protection System Coordination Study is required based on the option(s) selected. For Option 2, the drafting team interprets both of your statements to be correct.

The language and intent of the requirements contained in the final standard will be reflected in the final RSAW.

An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

Requirement R1, Parts 1.3.1 and 1.3.4 use the term “electrically joined Facilities” and are referring to Requirement R1, Part 1.3 which uses the phrase: “For Protection System settings applied on BES Elements that electrically join Facilities...” The drafting team asserts that no definition is necessary. For your example, sub 2 is electrically joined to sub 1; however, because the Protection Systems in both subs are owned by the same functional entity, Requirement R1, Part 1.3 is not applicable.

The note “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.” is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. If an entity has a single group performing its coordination work for separate functional entities within an organization, it should make that declaration in its process.

In the case where utility A performs the settings calculations for both parties (utility A & B), those settings and the associated documentation for those settings would need to be sent to utility B. Utility A would not be responsible for utility B compliance. Note that utility B is required to develop a process that may include the use of contractors to develop Protection System settings.

Yes. The drafting team agrees with your interpretation.

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Group Name: NPCC--Project 2007-06 PRC-027-1

Group Member Name	Entity	Region	Segments
Alan Adamson	New York State Reliability Council, LLC	NPCC	10
David Burke	Orange and Rockland Utilities Inc.	NPCC	3
Greg Campoli	New York Independent System Operator	NPCC	2
Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
Mark Kenny	Northeast Utilities	NPCC	1

Helen Lainis	Independent Electricity System Operator	NPCC	2
Rob Vance	New Brunswick Power Corporation	NPCC	9
Paul Malozewski	Hydro One Networks Inc.	NPCC	1
Bruce Metruck	New York Power Authority	NPCC	6
Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
Brian Robinson	Utility Services	NPCC	8
Wayne Sipperly	New York Power Authority	NPCC	5
Edward Bedder	Orange and Rockland Utilities Inc.	NPCC	1
Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
Michael Jones	National Grid	NPCC	1
Brian Shanahan	National Grid	NPCC	1
Michael Forte	Consolidated Edison Co. of New York, Inc.	NPCC	1
Glen Smith	Entergy Services, Inc.	NPCC	5
Brian O'Boyle	Consolidated Edison Co. of New York, Inc.	NPCC	8
RuiDa Shu	Northeast Power Coordinating Council	NPCC	10
Connie Lowe	Dominion Resources Services, Inc.	NPCC	5
Guy Zito	Northeast Power Coordinating Council	NPCC	10
Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
Kathleen Goodman	ISO - New England	NPCC	2
Robert Pellegrini	The United Illuminating Company	NPCC	1

Answer Comment:

The parenthetical phrase in sub-Part 4.1.3 of the Applicability is not necessary and should be deleted. FPA 215 already ready limits the applicability of all reliability standards to the Bulk Power System and believe that NERC has revised the BES definition so that it should, either through application of bright line criteria or through the NERC or FERC exception process, encompass only those Elements and Facilities that are subject to FPA 215.

It should also be noted that, in this version the word “its” is deleted from Requirement 1 but that the Rationale for Requirement R1 uses the word “their” while Measure 1 uses the word “its”. We suggest changes be made so that all contain consistent verbiage. We believe that an entity can only be responsible for Protection System(s) it owns and would prefer this be explicitly indicated in the requirement(s).

As defined in the NERC Glossary, the Reliability Coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and Real-time operations. The Reliability Coordinator has the purview above and beyond that of a Transmission Operator that is broad enough to enable the calculation of Interconnection Reliability Operating Limits. Because new relay settings or revisions to relay settings can impact IROL calculations, the Reliability Coordinator must be aware of any new relay settings or revised relay settings in advance of their implementation.

For these reasons the standard needs to require that each Transmission Owner, Generator Owner and Distribution Provider notify the Reliability Coordinator that it is developing new or revised relay settings. The revision should also allow for the Reliability Coordinator to provide comments on the new or revised relay settings. To capture this, we suggest the following revision to R1:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1. A review and update of short-circuit models for the BES Elements under study.

1.2. A review of the developed Protection System settings.

1.3. Provide new or revised Protection System settings to the Reliability Coordinator.

1.3.1 Respond to the Reliability Coordinator's comments regarding the proposed new or revised Protection System settings by resolving any coordination issue(s) or affirming that no coordination issue(s) were identified.

1.4. For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.4.1. Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Also, to clarify and reinforce the nature of the broader protection coordination concern, suggest the following modification to the Purpose:

“To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults without causing an inadvertent adverse impact anywhere on the BES.”

We suggest that the drafting team review PRC-027-1 R1 Part 1.1 and MOD-032-1, R1 for a potential overlap, and if necessary provide clarification in the supplemental material.

R2, Option 2 has two actions associated with it, both of which have to be completed in one timeframe. The two actions are the Fault current comparison against the baseline and the performance of a Protection System Coordination Study if the fault current comparison exceeds 15% or greater deviation. It is recommended that under this option, if an entity identifies a 15% or greater deviation in Fault current value at a bus, the entity is given a set amount of time per element to complete a protection coordination study on all applicable elements at that bus.

In many cases, smaller entities that are interconnected to larger TOs do not develop their own Protection System settings. These settings are provided to them by the interconnecting TO and mandated to be implemented through Interconnection agreements. R1 should be revised to recognize these instances, including the Rationale for Requirement R1 words related to a “single protective relaying group performing the work for multiple functional entities,” as a single group may be responsible for the process for multiple owners of BES Elements. The note should also be included in the Requirement and Measure as internal documentation will be used to determine the coordination aspects of Part 1.3.

Requirement R3 needs a "trigger" to initiate the process described therein. Suggest revising Requirement R3 to read:

R3. Each Transmission Owner, Generator Owner, and Distribution Provider that determines a need for new or revised Protection System settings shall utilize its process established in Requirement R1 to develop new and revised Protection System settings for BES Elements.

To avoid confusion between modeling and protection short circuit modeling, suggest adding the word "protection" to make the term used in the standard "protection short circuit".

Response: Thank you for your comments.
The drafting team included the parenthetical to address comments received from Distribution Providers that wanted additional clarity during previous postings of PRC-027-1.

It is the intent of the drafting team that an entity is only responsible for its Protection Systems and the team asserts that the language in the requirement and the measure is clear. The drafting team declines to make the suggested change.

The drafting team appreciates the suggestions but contends they do not add to reliability and declines to make the suggested changes to the requirements and purpose of the draft standard.

There is no overlap or conflict between PRC-027-1 Requirement R1, Part 1.1 and MOD-032-1, Requirement R1. Requirement R1 Part 1.1 of PRC-027-1 ensures that the short-circuit model data is reviewed for accuracy before being used to develop new or revised Protection System settings.

Option 2 of Requirement R2 is a Fault current based methodology for determining when a Protection System Coordination Study (PSCS) must be performed for Protection System functions listed in Attachment A. The second action you mention (performing a PSCS) is only required when a 15% or greater deviation from the established baseline Fault current at the bus to which the Element is connected is identified. An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

The note “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.” is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. If an entity has a single group performing its coordination work for separate functional entities within an organization, it should make that declaration in its process. The note is also included in the RSAW.

The drafting team contends that Requirement R3 is clear that the trigger for utilizing your process is whenever you need to develop new or revised Protection System settings. The drafting team declines to make the suggested change.

The drafting team declines to make the suggested change.

Andrea Jessup - Bonneville Power Administration - 1,3,5,6 - WECC

Answer Comment: N/A

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment: Texas RE recommends deleting the comment regarding ownership in the Functional Entities section since there is no need with risk-based compliance.

In the Evidence Retention section, Texas RE recommends changing the statement "since the last audit" to "since the last audit of these requirements."

Response: Thank you for your comments.

The drafting team included the parenthetical to address comments received during previous postings of the draft standard from Distribution Providers requesting additional clarity.
The referenced language in the Evidence Retention section is boilerplate language. The drafting team declines to make the suggested change.

Kenn Backholm - Snohomish County PUD No. 1 - 6 -

Answer Comment: Public Utility District No. 1 of Snohomish County supports Salt River Project comments.

Oshani Pathirane - Oshani Pathirane On Behalf of: Paul Malozewski, Hydro One Networks, Inc., 1, 3
Payam Farahbakhsh, Hydro One Networks, Inc., 1, 3

Answer Comment:

1) Hydro One Networks Inc. agrees with the NPCC and recommends that the NERC SDT provides clarification on the overlap of requirements between MOD-032-1, R1 (to develop short-circuit modelling data requirements) and PRC-027-1, R1 (to establish a process which includes a review and update of short-circuit models).

2) Requirement R2, Option 2, entails two actions: 1) a fault current comparison against a previously established baseline be performed, and 2) a Protection System Coordination Study be performed if the results of the comparison study

exceed a deviation 15%. Presently, both these actions need to be performed within the same timeframe. However, Hydro One Networks Inc. agrees with the NPCC in that a separate time period should be allotted for an entity to complete a protection coordination study on all associa0ted elements on a bus, if a deviation of 15% or greater in the available fault current comparison is identified.

3) Further, Hydro One Networks Inc. also recommends that in the interest of clarity, the two actions within Option 2 of requirement R2 be separated out.

Response: Thank you for your comments.

There is no overlap or conflict between PRC-027-1 Requirement R1, Part 1.1 and MOD-032-1, Requirement R1. Requirement R1 Part 1.1 of PRC-027-1 ensures that the short-circuit model data is reviewed for accuracy before being used to develop new or revised Protection System settings.

Option 2 of Requirement R2 is a Fault current based methodology for determining when a Protection System Coordination Study (PSCS) must be performed for Protection System functions listed in Attachment A. The second action you mention (performing a PSCS) is only required when a 15% or greater deviation from the established baseline Fault current at the bus to which the Element is connected is identified. An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

The drafting team declines to make the suggested change.

Carol Chinn - Florida Municipal Power Agency - 4 -

Group Name:	FMPA

Group Member Name	Entity	Region	Segments
Tim Beyrle	City of New Smyrna Beach	FRCC	4
Jim Howard	Lakeland Electric	FRCC	3
Greg Woessner	Kissimmee Utility Authority	FRCC	3
Lynne Mila	City of Clewiston	FRCC	3
Javier Cisneros	Fort Pierce Utility Authority	FRCC	4
Randy Hahn	Ocala Utility Services	FRCC	3
Don Cuevas	Beaches Energy Services	FRCC	1
Stan Rzad	Keys Energy Services	FRCC	4
Matt Culverhouse	City of Bartow	FRCC	3
Tom Reedy	Florida Municipal Power Pool	FRCC	6
Steven Lancaster	Beaches Energy Services	FRCC	3
Mike Blough	Kissimmee Utility Authority	FRCC	5
Mark Brown	City of Winter Park	FRCC	3
Mace Hunter	Lakeland Electric	FRCC	3

Answer Comment:

1. From a standards development process perspective, FMPA recognizes that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written “consideration of comments” would have been helpful. Plus, is it surprising that this round of questions only addresses the “Attachment A” and the “Implementation Plan” and not the actual standard language. These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

2. Requirement 1.3.4 has 4 sub parts that can drive auditors to require registered entities to prove the negative. Would suggest that the four sub parts be not listed as such and instead just be collapsed into the sentence. That will reduce the likelihood that auditors will feel compelled to ask for “specific

supporting evidence to prove the negative" which we were told during outreach was not the intent of the SDT.

Part 1.3.4 *Communicate with the other owner(s) of the electrically-joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during:*

1.3.4.1. *Implementation or commissioning.*

1.3.4.2. *Misoperation investigations.*

1.3.4.3. *Maintenance activities.*

1.3.4.4. *Emergency replacements required as a result of Protection System component failure.*

3. FMPA has previously commented that the speed at which faults are cleared is very important to reliability, and does not understand why sequence is call out in the standard and associated definitions as being more important. FMPA recommends the SDT consider adding language to R1 that requires review of Protection System settings with regard to critical clearing time.

Response: Thank you for your comments.

The drafting team appreciates your thoughts regarding a "consideration of comments" document from the previous posting and the concerning the questions associated with the most recent posting. The drafting team received many constructive changes during the previous comment period for draft 5 of the standard and chose to adopt many of them, incorporating them into draft 6. The team concentrated on improving the standard rather than responding to the many comments received. With this past posting, the questions reflected two primary aspects of the standard along with the general question that is designed to capture all other topics stakeholders want addressed or have questions on. Based on the comments submitted with this posting, that effort was successful.

The drafting team reformatted Requirement R1, Part 1.3.4 to address your concern. It now reads: Communicate with the other owner(s) of the electrically joined Facilities regarding revised Protection System settings resulting from unforeseen circumstances that arise during implementation or commissioning, Misoperation investigations, maintenance activities, or emergency replacements required as a result of Protection System component failure.

The drafting team asserts that critical clearing times are developed in planning studies and System performance is assessed through the TPL standards. PRC-027-1 is addressing the coordination of Protection Systems such that they operate in the intended sequence during Faults.

Rachel Coyne - Texas Reliability Entity, Inc. - 10 -

Answer Comment:

Texas RE recommends deleting the comment regarding ownership in the Functional Entities section since there is no need with risk-based compliance.

In the Evidence Retention section, Texas RE recommends changing the statement “since the last audit” to “since the last audit of these requirements.”

Texas RE is concerned there is no time frame for entities to provide settings or response to settings in R1.3 The implication is that setting should be provided before implementation by using the word “proposed” but R1.3.2 does not discuss any timeframe for a response. R1.3.4 does not discuss a time frame for communication of revised settings in an unforeseen circumstance.

The footnote for R2 could cause confusion. It is not clear that an Entity should not exceed six years between either performing a Study or comparing Fault current values. If an entity changes options before the six year mark, a Study should be done at that time to establish the baselines.

Texas RE recommends changing the severe VSL for R2 to “The responsible entity failed to perform Option 1, Option 2 or Option 3, in accordance with Requirement 2 for each element.”

Response: Thank you for your comments.

The drafting team included the parenthetical to address comments received during previous postings of the draft standard from Distribution Providers requesting additional clarity.

The referenced language in the Evidence Retention section is boilerplate language. The drafting team declines to make the suggested change.

The drafting team provided flexibility for entities to establish processes that best work for their protection philosophies and business practices. Communication with neighboring entities is required for certain provisions within the process; the drafting team asserts that entities will collaborate on schedules to ensure both parties’ needs are met.

The drafting team asserts the language of Requirement R2 and the footnote are clear.

The drafting team asserts the phrase “in accordance with Requirement R2” is sufficient, and declines to make the suggested change to the VSL.

Alex Chua - Pacific Gas and Electric Company - 5 -

Answer Comment: Abstain

Matt Culverhouse - City of Bartow, Florida - 3 -

Answer Comment:

1. From a standards development process perspective, we recognize that there was a fair amount of industry outreach recently on this Project. Yet, given the low results (<40%) in the prior balloting, a written "consideration of comments" would have been helpful. Plus, is it surprising that this round of questions only addresses the "Attachment A" and the "Implementation Plan" and not the actual standard language. These few questions will not necessarily gather the input needed by the SDT, in case additional improvements are needed.

Response: Thank you for your comment. The drafting team appreciates your thoughts regarding a "consideration of comments" document from the previous posting and the concerning the questions associated with the most recent posting. The drafting team received many constructive changes during the previous comment period for draft 5 of the standard and chose to adopt many of them, incorporating them into draft 6. The team concentrated on improving the standard rather than responding to the many comments received. With this past posting, the questions reflected two primary aspects of the standard along with the general question that is designed to capture all other topics stakeholders want addressed or have questions on. Based on the comments submitted with this posting, that effort was successful.

Patricia Robertson - BC Hydro and Power Authority - 1 -

Group Name: BC Hydro

Group Member Name	Entity	Region	Segments
Patricia Robertson	BC Hydro and Power Authority	WECC	1
Venkataramakrishnan Vinnakota	BC Hydro and Power Authority	WECC	2
Pat G. Harrington	BC Hydro and Power Authority	WECC	3
Clement Ma	BC Hydro and Power Authority	WECC	5

Answer Comment:	The requirement to coordinate protective relay settings has existed since the first power systems were built. BC Hydro, like all utilities, has been coordinating their protection systems as part of their normal practice and has a process for setting development, review and implementation on its protection systems. While the requirements in Draft 6 of PRC-027-1 are not substantially different than standard industry practice, proving annual compliance with these requirements (to the satisfaction of lawyers) will impose a large administrative burden. The original focus of PRC-001 made sense in that there are always communications and data gathering issues that make coordinating protection systems across different utilities more challenging than coordinating within one's own system. The new draft standard focuses too much of the utility's time and effort on proving compliance on a process that typically works well, which reduces the amount of time and effort that can be spent on areas where more time and money should be spent.

Response: Thank you for your comment. The drafting team agrees that most entities have processes to develop Protection System settings that achieve proper coordination of the Bulk Electric System. Utilizing each of the elements of the process ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System. The drafting team contends these requirements were crafted in a manner that provides entities the ability to continue to follow their individual protection philosophies and practices, with minimal administrative impact.

Ben Li - Independent Electricity System Operator - 2 - NPCC

Group Name: ISO/RTO Council Standards Review Committee

Group Member Name	Entity	Region	Segments

Charles Yeung	SPP	SPP	2
Greg Campoli	NYISO	NPCC	2
Ali Miremadi	CAISO	WECC	2
Ben Li	IESO	NPCC	2
Kathleen Goodman	ISO-NE	NPCC	2
Mark Holman	PJM	RFC	2
Terry Bilke	MISO	MRO	2

Answer Comment:

The Planning Coordinator, Reliability Coordinator, and Balancing Authority must be notified when new or revised protection settings are developed.

As defined in the NERC Glossary, the Planning Coordinator is the responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems. Because the Planning Coordinator is responsible for the coordination and integration of protection systems, it must be aware of any new relay settings or revised relay settings in advance of their implementation.

As also defined in the NERC Glossary, the Reliability Coordinator is the entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision. Because new relay settings or revisions to relay settings can impact IROL calculations, the Reliability Coordinator must be aware of any new

relay settings or revised relay settings in advance of their implementation.

Finally, draft requirements in the proposed TOP-009-1 reliability standard require that the Balancing Authority ensure that "… its personnel responsible for Reliable Operation of its Balancing Authority Area have knowledge of operational functionality and effects of Composite Protection Systems and Remedial Action Schemes that are necessary to perform its Real-time monitoring in order to maintain generation-Load-Interchange balance." Accordingly, Balancing Authorities will need to be provided with new or revised Protection System settings to fulfill its obligations under TOP-009-1.

Therefore, the standard needs to require that each Transmission Owner, Generator Owner and Distribution Provider notify the Planning Coordinator, Reliability Coordinator, and Balancing Authority that it is developing new or revised relay settings. The revision should also allow for the Planning Coordinator or Reliability Coordinator to provide comments on the new or revised relay settings. To capture this, the ISO/RTO Council Standards Review Committee suggests the following revision in R1:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a process for developing new and revised Protection System settings for BES Elements, such that the Protection Systems operate in the intended sequence during Faults. The process shall include: *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]*

1.1 A review and update of short-circuit models for the BES Elements under study.

1.2 A review of the developed Protection System settings.

1.3 Provide new or revised Protection System settings to the Planning Coordinator, Reliability Coordinator, and Balancing Authority.

1.3.1 Respond to the Planning Coordinator or Reliability Coordinator's comments regarding the proposed new or revised Protection System settings.

1.4 For Protection System settings applied on BES Elements that electrically join Facilities owned by separate functional entities (Transmission Owners, Generator Owners, and Distribution Providers), provisions to:

1.4.1 Provide the proposed Protection System settings to the owner(s) of the electrically-joined Facilities.

Also, to clarify and reinforce the nature of the broader protection coordination concern, the following modification to the Purpose is proposed:

"To maintain the coordination of Protection Systems installed to detect and isolate Faults on Bulk Electric System (BES) Elements, such that those Protection Systems operate in the intended sequence during Faults without causing an inadvertent adverse impact anywhere on the BES."

Response: Thank you for your comments.
The drafting team appreciates the suggestions but contends those changes are not necessary in PRC-027-1. Between Phase 1 and Phase 2 of System Protection Coordination, all of the planning and operational aspects of coordination are addressed. The drafting team declines to make the suggested changes.

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

Group Name:	Southern Company

Group Member Name	Entity	Region	Segments
Robert A. Schaffeld	Southern Company Services, Inc.	SERC	1
R. Scott Moore	Alabama Power Company	SERC	3
William D. Shultz	Southern Company Generation	SERC	5
John J. Ciza	Southern Company Generation and Energy Marketing	SERC	6

Answer Comment:

We request that the SDT consider the following changes/ clarifications:

Present language:

R1.1 A review and update of short-circuit models for the BES Elements under study.

Proposed:

R1.1 A review and update of short-circuit models or data for the BES Elements under study.

This change will address concerns from GOs and DPs that don't have anything to do with the short-circuit model and potentially only need the fault current data at the interconnected bus from the TO.

In the rational box for **R2:**

Present language:

The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners and Planning Coordinators.

Proposed language:

The Fault current baseline values can be obtained from the short-circuit studies performed by the Transmission Planners, Planning Coordinators or Transmission Owners.

Response: Thank you for your comments. The drafting team made the suggested clarifying changes.

Tony Eddleman - Nebraska Public Power District - 3 -

Answer Comment:

Please state that when a fault current baseline is first established we are not required to show a coordination study for every protection scheme on our system. Please state that utilities are not required to show a coordination study if the baseline continues to show a fault current change less than 15%?

Requirement R2 option 2 states “Fault current values (either three phase or phase to ground) at a bus to which the Element is connected” where the RSAW states “Fault current comparison and results for each BES Element”. The RSAW and Standard should match language as closely as possible. In this case the standard states bus faults and the RSAW evidence specifies each element which is more than just a bus. It may be wise to delay industry RSAW reviews until the standard language is in a more finalized state.

Consider adding a modification to R2. There should be an allowed time line for a coordination study to take place after the 15% fault current threshold has been identified as being exceeded. This presents a risk many could step into unwittingly when the identification is close to the 6 year interval. There are circumstances where fault currents may not change until close to this 6 year interval due to system changes that may not be foreseen. We suggest the requirement include a two year window after a 15% change is identified.

Please provide a definition or examples to clarify what is considered "electrically-joined Facilities". For example, if a line and both terminals and protection is owned by entity A at sub 1 and sub 2. All other equipment at sub 1 is owned by entity B. All equipment at Sub 2 is owned by entity A. Is sub 2 "electrically-joined"?

The RSAW in the sections for R1 and R3 states: "In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation". We request a provision in the Standard allowing if all separate functional entities within an organization have access to the same internal documentation, then the communication aspects are not required.

In a situation where utility A does work for another utility B on their transmission system protection equipment and utility A owns all the other surrounding protection systems, please clarify how the communication evidence would change with coordination work since utility A is making all the coordination decisions. Is it acceptable to show utility A has all utility B protection system settings internally stored? Does this make utility A responsible for utility B compliance?

For a facility that has multiple bus voltages such as 115kV, 230kV and 345kV and if the fault current baseline exceeds 15% on just the 115kV bus does this mean just the elements connected to the 115kV bus must have a coordination study but not the 230 or 345kV buses?

Response: Thank you for your comments.

The drafting team asserts that Requirement R2 and the footnote clearly indicate when a Protection System Coordination Study is required based on the option(s) selected. For Option 2, the drafting team interprets both of your statements to be correct.

The language and intent of the requirements contained in the final standard will be reflected in the final RSAW.

An entity can judiciously select the interval that a comparison of present Fault current values to an established Fault current baseline is made; thereby allowing adequate time after the identification of the Fault current deviation to perform the Protection System Coordination Study.

Requirement R1, Parts 1.3.1 and 1.3.4 use the term “electrically joined Facilities” and are referring to Requirement R1, Part 1.3 which uses the phrase: “For Protection System settings applied on BES Elements that electrically join Facilities...” The drafting team asserts that no definition is necessary. For your example, sub 2 is electrically joined to sub 1; however, because the Protection Systems in both subs are owned by the same functional entity, Requirement R1, Part 1.3 is not applicable.

The note “In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation.” is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. If an entity has a single group performing its coordination work for separate functional entities within an organization, it should make that declaration in its process.

In the case where utility A performs the settings calculations for both parties (utility A & B), those settings and the associated documentation for those settings would need to be sent to utility B. Utility A would not be responsible for utility B compliance. Note that utility B is required to develop a process that may include the use of contractors to develop Protection System settings.

Yes. The drafting team agrees with your interpretation.

Likes: 1 Nebraska Public Power District, 1, Cawley Jamison
Nebraska Public Power District, 1, Cawley Jamiso

Dislikes: 0

Ginette Lacasse - Seattle City Light - 1,3,4,5,6 - WECC

Group Name: Seattle City Light Ballot Body

Group Member Name	Entity	Region	Segments
Pawel Krupa	Seattle City Light	WECC	1
Dana Wheelock	Seattle City Light	WECC	3
Hao Li	Seattle City Light	WECC	4
Bud (Charles) Freeman	Seattle City Light	WECC	6
Mike haynes	Seattle City Light	WECC	5
Michael Watkins	Seattle City Light	WECC	1,3,4
Faz Kasraie	Seattle City Light	WECC	5
John Clark	Seattle City Light	WECC	6

Answer Comment:

SCL GENERAL COMMENTS

1) The Option 2 baseline should include a system-wide review of the entities instantaneous overcurrent elements, that are utilized on the BES, as well as the performance of the baseline fault study.

SCL experience has demonstrated that overreaching instantaneous overcurrent elements are one of the largest causes of miscoordination in a Protective Relay System.

2) The draft Standard, in its present form, is reminiscent of the early stages of the PRC-005 (Relay Maintenance) Standard, in that each utility will establish their own implementation (issue and installation of the relay settings) schedule timeline, without any constraints. This did not work well, for Standard PRC-005 as the utilities with strong maintenance plans were scrutinized, during audits, much more rigorously than those utilities with weaker maintenance plans, even though the weaker maintenance plans made the BES less reliable. It required several revisions of the PRC-005 Standard to get everyone on the same playing field. SCL believes that a similar situation will occur if a not-to-exceed schedule timeline is not established for the implementation of the revised relay settings.

R1. - Introduction

Modify text in paragraph to read: such that the Protection Systems, associated with the protective functions listed in Attachment A, operate in the intended sequence during faults.

R1. – Add Section 1.4

Inside of this section describe the timeline allowed to implement the revised relay settings.

For example, “new and revised relay settings necessary for the coordination of the Protection Systems, associated with the protective functions listed in Attachment A, shall be issued and installed within one year after the Protection Coordination Study has been performed”.

R2. – Option 2

Modify text in paragraph to include the following steps:

1) Compare the present fault current values to the previously established fault current baseline at each BES bus within the entitiy’s system, with Protection Systems, associated with the protective functions listed in Attachment A.

2) Identify the buses where the present fault current value exceeds the baseline value by an amount that is 15%, or greater, in magnitude.

3) Perform a Protection System Coordination Study on the area of the system defined by the BES elements that are connected to the buses identified in Step 2.

4) The time interval to perform steps 1-3 shall not exceed six calendar years.

ATTACHMENT A

Modify text for relay elements as follows (line number defined at beginning of sentence):

21-1 – Zone 1 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

21-2 – Zone 2 distance relay if:

• Infeed is used in determining reach (phase & ground distance), or

• zero-sequence mutual coupling is used in determining reach (ground distance)

50 – Instantaneous overcurrent

51 – AC inverse time overcurrent if used in a non-communication-assisted protection scheme.

67 I – Directional Instantaneous overcurrent

67 T – Directional inverse time overcurrent if used in a non-communication-assisted protection scheme.

SUPPLEMENTAL MATERIAL REQUIREMENT R1

Modify the text for the last paragraph of Section R1 just above Part 1.1 to read:

The coordination of some Protections Systems may seem unnecessary, such as for a line element that is protected solely by dual current differential relays with other Protection Systems of the line element such that tripping does not unnecessarily occur for faults outside of the differential zone, unless there is a Protection System failure on the adjacent line element.

Response: Thank you for your comments.

The standard does not preclude an entity from performing a system-wide review of its instantaneous overcurrent elements, if desired. The drafting team declines to make the suggested change.

The drafting team declines to make the suggested changes.

Andrew Pusztai - American Transmission Company, LLC - 1 -

Answer Comment: ATC recommends revising PRC-027-1 to identify a clear connection between performance and the requirements of this standard. Where PRC-004 data provides a mechanism to measure performance, the better means to achieve reliability performance would allow each entity to use its company's misoperations data and the greater industry data to develop a program that addresses its greatest need.

Response: Thank you for your comment. PRC-027-1 does not preclude an entity from evaluating its System based on PRC-004 data as another tool to minimize Misoperations due to coordination issues.

Ben Engelby - ACES Power Marketing - 6 -

Group Name: ACES Standards Collaborators - PRC-027 Project

Group Member Name	Entity	Region	Segments
Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3,4
Mike Brytowski	Great River Energy	MRO	1,3,5,6
Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
Ginger Mercier	Prairie Power, Inc.	SERC	1,3
Bill Hutchison	Southern Illinois Power Cooperative	SERC	1

John Shaver	Arizona Electric Power Cooperative, Inc. Southwest Transmission Cooperative, Inc.	WECC	1,4,5
Chip Koloini	Golden Spread Electric Cooperative, Inc.	SPP	5

Answer Comment:

1. For requirement R1, Part 1.1, the requirement states that the TO, GO, and DP must have a process to review and update short-circuit models for BES Elements under study. We disagree that the GO and DP must complete their own short-circuit models. Our recommendation is to allow GOs and DPs to use the TO’s short circuit study for applicable GO or DP buses.
2. For requirement R1, Part 1.3, we disagree with the requirement of documenting internal coordination, especially considering that smaller entities may have a single protection engineer that is responsible for completing the study. Also, we disagree that there needs to be eight sub-parts for joint ownership coordination. This is administrative in nature and burdensome for compliance. This sub-part is overly complicated and creates opportunities for entities to fall out of compliance. There is little benefit to reliability for having this much detail required.
3. For requirement R2, option 1, performing studies for all applicable relays can be resource intensive, especially for smaller entities. We recommend that the drafting team consider the Cost Effective Analysis Process (CEAP) to determine if the reliability benefits outweigh the cost of compliance.
4. For requirement R2, option 2, the baseline process is complicated. We recommend stating in footnote one that the baseline for option 2 must be completed within 12 months after the standard goes into effect. Also, the measure should state that if there is not a fault current deviation greater than 15 percent, then an attestation is sufficient evidence for compliance.
5. For requirement R2, option 3, there should be specific guidance in the measures to demonstrate compliance for the combined approach, such as a

baseline for applicable distance or overcurrent relays to occur within 12 months of the effective date and a Protection System Coordination Study (PSCS) for the remaining applicable Protection Systems to occur every 6 years after the effective date.

6. For requirement R3, the documentation requirements for coordination activities of new/revised settings is administrative in nature. We question the need for an administrative documentation requirement that is assessed a high risk. Industry has long history of coordinating Protection Systems and there is not any evidence of a widespread lack of Protection System coordination. We do not see how requiring a documented process will reduce the risks to reliability. Thus, we do not see how it enhances reliability and believe it could actually detract by causing applicable entities to focus on paperwork.

Response: Thank you for your comments.

The drafting team made a clarifying change in the Requirement and complementary changes in the Rational Box and Supplemental Material.

The note "In cases where a single protective relaying group performs coordination work for separate functional entities within an organization, the communication aspects of Requirement R1, Part 1.3 can be demonstrated by internal documentation." is intended to minimize the documentation requirements for the subject functional entities. A single document that provides the required evidence would be sufficient for use by both functional entities. The drafting team contends that Part 1.3 is not administrative. The reliability objective is to ensure that the owners of Protection Systems have communicated and addressed any identified coordination issues prior to implementing the Protection Systems.

The drafting team does not agree that the work associated with Requirement R2, Option 1 is extensive, particularly for smaller entities. Entities have the choice to utilize Option 2.

Based on yours and others comments, the drafting team lengthened the implementation period of the standard to twenty-four months to provide an entity adequate time to establish its Protection System settings development process, establish Fault Current baselines, and establish a tracking tool for Fault Current baseline changes and/or Protection System Coordination Studies.

The drafting team contends that utilizing the process established in Requirement R1 ensures a consistent approach to the development of accurate Protection System settings, decreases the possibility of introducing errors, and increases the likelihood of maintaining a coordinated Protection System.

Doug Hohlbaugh - FirstEnergy - Ohio Edison Company - 4 -

Answer Comment:

FE's primary concern relates to what is required of the GO to be able to comply with R1 which states the TO, GO and DP "… establish a process to develop settings for its BES Protection Systems to operate in the intended sequence during Faults." The GO, operates the units essentially as isolated BES elements. The term "sequence" infers it is referring to the BES as a whole, at least with regard to interconnected elements, which would then mean we need a joint process with the TO. The GO is not in a position to make that happen, nor should the GO have primary responsibility. This should be a TO responsibility, with GO providing settings as requested by TO, and GO changing settings as requested/instructed by the TO.

FE believes the TO should be identified as the entity to establish the system protection coordination and be responsible for PSCSs (Power System Coordination Studies), Fault Studies, Short Circuit Studies, etc., to prove coordination. Communication to the GO should also be the TO's responsibility. The GO would be responsible to implement setting changes as directed by the TO, where applicable and if able. The GO's connection to the BES normally ends/terminates with the Generator Step Up transformer so the GO does not have the data to perform any Power System Coordination Studies, Fault Studies, or Short Circuit Studies

Response: Thank you for your comments.

The drafting team disagrees with your premise. The drafting team contends that the Generator Owner needs to have a process to develop its Protection System settings and must follow Requirement R1, Part 1.3 to ensure they coordinate with the Transmission Owner. The Generator Owner has the ultimate responsibility, not the Transmission Owner, for setting its Protection Systems such that they operate in the intended sequence during Faults.

The drafting team agrees that the Transmission Owner may provide the Generator Owner the short-circuit model data; however, the Generator Owner still needs to have a process to develop its Protection System settings and must follow Requirement R1.

End of report