Survey Report

Survey Details

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

Description

Start Date 4/1/2015

End Date 5/15/2015

Associated Ballots

2007-06 System Protection Coordination PRC-027-1 & PRC-001-1.1(ii) IN 1 ST

Survey Questions

See the Unofficial Comment Form on the [Project Page] for additional background information.

If you would like to bypass taking the survey, click the radio button and scroll down to submit the survey.

This will allow you to view Social Survey and agree / disagree with an already posted comment using the "thumbs up / thumbs down" feature.

Submitting a "thumbs up / thumbs down" on another entity's comment enables a negative vote to count in the calculation of consensus.

I want to bypass taking the survey

1. Do you agree that Parts 1.1 through 1.5 of Requirement R1 are the essential elements of a successful coordination process? Are there others that should be included? If not, please provide the basis for your disagreement and any proposed revisions or additions.

Yes

No

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

Yes

No

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

Yes

No

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

Responses By Question

See the Unofficial Comment Form on the [Project Page] for additional background information.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0
John Fontenot - Bryan Texas Utilities - 1 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0
Robert Hirchak - Cleco Corporation - 6 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

Document Name:

Likes:	0	
Dislikes:	0	

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	1	Oxy - Occidental Chemical, 7, Greaff Venona
Dislikes:	0	

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Document Name:

Likes:	0	
Dislikes:	0	

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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:

Document Name:

Likes: 2 Colorado Springs Utilities, 5, Brimhall Kaleb
Colorado Springs Utilities, 1, Speer Shawna

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 2 Nebraska Public Power District, 5, Schmit Don
Nebraska Public Power District, 3, Eddleman Tony

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Colorado Springs Utilities, 1, Speer Shawna

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name: PRC-027-1_Unofficial_Comment_Form_04012015_May14.doc

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name: HYDRO ONE NETWORKS INC PRC-027-1_Unofficial_Comment_Form_04012015.docx

Likes: 1 Hydro One Networks, Inc., 3, Malozewski Paul

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

If you would like to bypass taking the survey, click the radio button and scroll down to submit the survey.

This will allow you to view Social Survey and agree / disagree with an already posted comment using the “thumbs up / thumbs down” feature.

Submitting a “thumbs up / thumbs down” on another entity's comment enables a negative vote to count in the calculation of consensus.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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:

Document Name:

Likes: 0

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Santee Cooper, 3, Poston James

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer: I want to bypass taking the survey

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

1. Do you agree that Parts 1.1 through 1.5 of Requirement R1 are the essential elements of a successful coordination process? Are there others that should be included? If not, please provide the basis for your disagreement and any proposed revisions or additions.

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: No

Answer Comment:

1. Is it not clear what the differences between part 1.2 and 1.3 are.
2. Does 1.2 mean a Protection System settings review in a specific affected area due to some specific System changes? What kind of system changes (and how significant the changes are) would constitute a protection setting review?
3. Is 1.3 meant for a periodic overall review of the existing entity-designated protection system settings of all the BES elements that an entity owns? Based on 1.3, an entity has to do a fault study on every BES bus to determine if the fault current deviates by 15%. If the entity finds that the fault current at some of the BES busses indeed deviates by more than 15%, does the entity need to review the protection settings in the immediate area only or otherwise?

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer: No

Answer Comment:

It is confusing to the industry to have several standards pertaining to setting coordination. Why would NERC add a standard pertaining specifically to faults rather than simply revising the PRC-001 standard. Further there are several standards related to settings for generation ride through to disturbances, and UFLS settings requirements that muddy the waters of understanding and efforts required under this draft PRC-027.

Requirement (R4) of PRC-001 required the Transmission Owner to coordinate with Generation Owners on Transmission line settings. It is our belief that the TO should still be taking the lead in coordination in the draft PRC-027 requirements language.

Document Name:	
Likes:	0
Dislikes:	0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

We agree with Parts 1.2, 1.3 and 1.5 of Requirement R1, but disagree with Parts 1.1 and 1.4.

Part 1.1 is not results-based; it is overly prescriptive and an inherent and necessary element for developing new or revised Protection System settings. We suggest to remove it as it does not any value to Requirement R1.

R1.2. The wording in the draft standard is confusing. Suggest the following wording: "A review of the affected Protection System settings due to System changes as determined by the entity's process."

- The study should clearly mention that System changes will reset baseline for Fault current studies.

- The rationale box for R1.2 is open ended and may leave the impression that every change, even minor ones, will be considered a System change and be subject to an audit. The standard should better define "System changes."

Part 1.4 is unclear and unnecessary. It is unclear as to what constitutes a "quality review", and how is it measured. It is not necessary to perform any QR. If the intent is to have this included in the process document to ensure

new or revised protection system settings are properly coordinated, then this part should be revised to say, e.g.:

1.4 A check list to verify that the development of the new or revised protection system settings is coordinated among affected entities and that the proposed settings can achieve the intent of fault clearing prior to implementation.

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Wisconsin Electric supports the standard in concept but believes it needs more specificity. While in general we appreciate flexibility that the SDT wrote into the standard, we have seen that this leads to inconsistencies in application. Specifically, R1 states that entities shall establish a process for developing settings. It is very open ended and will be very subjective to evaluate.

We also think the timeline for activities needs to be better defined. For example, if in R1.3 you find that there has been a 15% deviation in fault current how long do you have to perform the review?

For R1.5 we need to communicate the settings to other entities and they shall review them. Does this need to be done before they are implemented or does the methodology in the procedure almost guarantee coordination? For R1.5 we would like to see in the measures what the acceptable evidence would be.

It was mentioned on the webinar that this is a forward looking standard and that no coordination review needs to be done unless triggered by R1.2 or R1.3. This should be specifically spelled out in the standard.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: No

Answer Comment:

1) Is it not clear what the differences between part 1.2 and 1.3 are.

2) Does 1.2 mean a Protection System settings review in a specific affected area due to some specific System changes? What kind of system changes (and how significant the changes are) would constitute a protection setting review?

3) Is 1.3 meant for a periodic overall review of the existing entity-designated protection system settings of all the BES elements that an entity owns? Based on 1.3, an entity has to do a fault study on every BES bus to determine if the fault current deviates by 15%. If the entity finds that the fault current at some of the BES busses indeed deviates by more than 15%, does the entity need to review the protection settings in the immediate area only or otherwise?

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer: No

Answer Comment:

Subrequirement 1.4 is too prescriptive. It has the nature of an internal control rather than a compliance process. Internal controls should be left to the discretion of the Entities, not included as auditable requirements. While we understand FERC's concern with MisOperations caused by incorrect settings, that can be addressed as part of the mitigation plan of entities who fail to properly maintain their protection systems and should not be reason to dictate internal controls to the rest of the industry.

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer: No

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 5 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.

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

Answer Comment:

AEP believes that R 1.2 is sufficient to cover coordination of all internal protection systems. As a result, R1 part 1.3 should be limited only to Protection Systems applied to BES Elements that electrically join Facilities owned by separate functional entities. This would require AEP to set baselines and keep track of fault currents at approximately 1800 buses. AEP has a process to review area coordination when system changes are made. All settings in an area that are affected by the change are reviewed and revised as necessary. Because of this process, it is not likely that any reviews of internal protection systems would result due to changes in fault current. Thus, this requirement would become an administrative burden without any reliability benefit for internal protection systems.

It is reasonable to require a periodic review 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.

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The PPL NERC Registered Affiliates believe that the requirements under PRC-027 for TO/TOP are acceptable but the inclusion of GOs in the applicability of this standards, as outlined below, is problematic. Without resolution of this concern PPL is unwilling to support the approval of this proposal.

The purpose of PRC-027-1 is to ensure that “Protection System components operate in the intended sequence during Faults,” but there is no sequencing of Protection System components within a generation plant. There is need for GOs to coordinate some Protection System settings with the TO, however, but this activity is already covered by other standards.

We raised these points in NERC’s 4/27/15 webinar on PRC-027-1, but the presenters did not address the issue and instead simply stated that GO-TO coordination of loadability relays is needed, adding that this task is described in various technical publications. We agree, and prominent among these sources is, “Coordination of Generator Protection with Generator Excitation Control and Generator Capability,” which is referenced on p.5 of PRC-019 and was specifically written for PRC-019. It covers GO-TO loss-of-field coordination in part V of the paper, and generator phase-backup coordination in part VI. That is, PRC-019-1 covers the supposed gap that PRC-027-1 is attempting to address.

We also disagree with the statement made during the webinar that PRC-025-1 deals only with acceptable setting ranges for loadability relays and not coordination. The “Background” section of this document makes it clear that the standard intends to accomplish coordination, and the tables and example calculations spell-out in detail how this is to be done.

The need mentioned on p.13 PRC-027 to communicate generator and GSU impedance changes to the TO is meanwhile already accomplished by MOD-010-0 (MOD-032-1 after 7/1/15). Supplemental GO relay-setting issues are covered by the existing standards cited on p.3 of PRC-027-1, and R2.1 of PRC-001-2 presents a catch-all mandate that "Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority."

PRC-027-1 is consequently redundant for GOs, nor is there any need to change PRC-001. Enacting PRC-027-1 in its present state would cause confusion, not close gaps. An entity believing that coordination of loadability relays will not be required until PRC-027-1 becomes effective may be cited for PRC-019-1 and PRC-025-1 violations, for example.

The SDT should carefully study existing standards and trim PRC-027-1 accordingly, including making it not applicable to GOs.

The quality review of PRC-027-1 R1.4 should also be deleted. We agree that entities should apply a prepared-by-reviewed-by-approved-by process in developing relay settings, but this is standard industry practice for all calculations and procedures. It is therefore unclear what new and special quality control activities justify setting PRC-027-1 apart from all other NERC standards in this respect.

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer: No

Answer Comment:

Ingleside Cogeneration (ICLP) believes that the scope of PRC-027-1 Draft 5 greatly extends beyond the concern initially raised by FERC staff. In our view, they are simply pointing out a similarity in purpose and structure between Fault relays protecting long transmission lines located fully within a single TO's footprint and those that interconnect to a neighboring TO, GO, or DP. Instead, the project team requires some level of disposition for every BES Protection System that reacts to a Fault.

Although we appreciate the flexibility allowed under Part 5.3 to designate the Protection Systems that are to be included in any one review, ICLP believes that CEAs will question any omission based upon design and/or susceptibility to changes in Fault current.

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

Tacoma Power generally agrees that Parts 1.1 through 1.5 of Requirement R1 are elements of a successful coordination process, but Tacoma Power does not agree that they are all 'essential.' Tacoma Power's specific comments follow.

Part 1.1. Tacoma Power believes that Part 1.1 is implied by the term 'review' in Parts 1.2, 1.3, and 1.5. Furthermore, as written, Part 1.1 may be difficult to audit under Requirement R2. Therefore, Tacoma Power recommends eliminating Part 1.1.

Part 1.2. Tacoma Power recommends the following verbiage for Part 1.2: "A method to review and, if necessary, update Protection System settings due to System and/or Protection System changes." Tacoma Power believes that Part 1.2 should focus on requiring a method, not the review itself, and that updates may be needed. Furthermore, as written in the current draft, Part 1.2 only refers to System changes, but an entity could change a Protection System without a System change, and this latter change could still require cascading Protection System changes. (If Part 1.4 is eliminated (see subsequent comments for Part 1.4), then the following verbiage is recommended for Part 1.2: "A method to review and, if necessary, update Protection System settings due to, and prior to implementation of, System and/or Protection System changes.")

Part 1.3. Tacoma Power generally supports Part 1.3. However, for periodic Fault current studies, no timeframe for reviewing existing entity-designated Protection System settings is specified following identification of a 15 percent or greater deviation in Fault current. To be consistent with the periodic review of Protection System settings, it is recommended that the interval for performing Fault studies, plus the timeframe to subsequently review Protection System settings, equals six calendar years, which means that Fault current studies should be performed more frequently than every six calendar years.

Part 1.3. Tacoma Power recommends changing “A review of...” to “A method to review and, if necessary, update...”

Part 1.3. Tacoma Power also recommends changing “A 15 percent or greater deviation in Fault current (either three-phase or phase-to-ground)...” to “A deviation in Fault current (either three-phase or phase-to-ground) greater than 15%...,” which should address some concerns that, for example, a 14.6% could be interpreted by an auditor as 15% due to rounding.

Part 1.3. Tacoma Power believes that clarification will be needed as to whether (1) an entity can choose between three-phase Fault current and phase-to-ground Fault current as a trigger or (2) an entity must use the greater change in the two Fault current values as a trigger.

Part 1.4. While it is a best practice, Tacoma Power does not believe that Part 1.4 is ‘essential.’ That said, if the drafting team elects to leave Part 1.4, Tacoma Power has the following comments. (1) Although rare, exceptions should be permitted (a) under bonafide emergencies and (b) when Protection System settings need to be altered during the implementation (commissioning) phase, provided that a follow-up review of quality is performed promptly (e.g., within 30 calendar days). (2) Tacoma Power recommends changing “A quality review of...” to “A review of the quality of...” (If the drafting team elects to eliminate Part 1.4, then Tacoma Power recommends that the verbiage in Part 1.2 be modified (see preceding comments for Part 1.2).)

Part 1.5. Tacoma Power generally supports Part 1.5. However, Tacoma Power believes that an exception to Part 1.5 should be granted when 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 entity are part of the same company.

Part 1.5. Tacoma Power recommends a fourth sub-part: “Communicate with the other functional entities that the Protection System settings were implemented, including any alterations to Protection System settings that needed to be made during implementation.” This additional sub-part helps to close the loop.

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Seattle City Light, like many urban utilities, has very short transmission lines that require the use of communication-assisted (pilot) schemes in order to provide proper sectionalizing (coordination) of the transmission system during a fault event. Guidance is not provided in the latest version of the standard for the coordination of pilot schemes and their backup relays (67N, e.g.). The 67N relays, located at the different buses, cannot be coordinated on our system per proposed PRC-027. To address this matter, Seattle recommends allowing miscoordination of the back-up scheme, under the standard, as long as the back-up scheme is only enabled whenever the communication-assisted (pilot) scheme has failed.

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The NSRF commends the SDT for the concept employed in the standard as we believe it addresses FERC's concerns and minimizes the impact on the Registered Entities. We do however have some specific comments that we believe should be addressed:

R1 states: *The **process** shall include:* , in R1.5, it states: ***procedures** to:*

The NSRF recommends that the word "procedures" be removed from R1.5.

R1.1: The requirement should be revised to "A method to review and update (when required) the information…" The industry has had past issues with do you need to update a process if there are no changes noted during your review. This addition will allow Entities to *review* and not *update* when no changes are required.

The second bullet of R1.3 states a Registered Entity must perform a "Periodic Review of Protection System settings" at a maximum interval not to exceed 6 years. In the Rational Box the SDT stated they chose 6 years because it corresponded to the maintenance period for certain relays. The NSRF believes this unfairly impacts owners of protective devices where the maintenance period is longer. Our recommendation is to revise the requirement to correspond to the maintenance period of the type of relay referenced in PRC-005. This way the setting comparison required by PRC-005 and the setting review can be accomplished at the same time making it more efficient. With thousands of Protection System relays to review every 6 years, there would be a large burden upon entities to outsource this activity. In our opinion there is not a large amount of risk in extending the interval because entities already review Protection System impacts in the areas where known construction activities change the electrical system. The second bullet of R1.3 should be revised to state "**Periodic Review of Protection Settings:** A time interval not to exceed that referenced in PRC-005 for a particular Protection System device."

Section 1.3 should be re-written to make it clear that an entity can conduct a condition based review within a given maximum time interval **and** as long as the conditions do not warrant a Protection System settings review, the comparison of the conditions to a baseline are satisfactory to prove compliance. If the conditions indicate a review should be conducted, then additional time should be granted to allow for the Protection System settings review.

The rationale for Section 1.3 should be carefully written as it states that a current differential protection scheme may not need to be included because changes in fault current will not affect the coordination of this system. The concern is that fault currents could increase to a point where CT saturation would prevent the current differential protection from operating as designed and therefore should be reviewed just like any other current sensitive protection system.

R1 section 1.4 should add clarity as to whether it applies to new or revised Protection System settings similar to R1 sections 1.1 and 1.5.

R1 section 1.5 needs to be re-written as it is fragmented and should state that the entity needs to establish a procedure and the procedure shall include the items covered under sections 1.5.1, 1.5.2 and 1.5.3. Suggested wording would be ". . . Distribution Providers), shall establish procedures to include the following items at a minimum:"

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

R1.1. “A method to review and update the information required to develop new or revised Protection Sytem settings” requires entities to develop a process to review information used in two studies: Short Circuit study and Protective Device Coordination study. R1.1. only addresses the ‘What’ but does not address the ‘When’. The ‘When’ for the review of the information used in the Protective Device Coordination study is addressed in R1.2 and R1.3; however, the ‘When’ for the review of information used in the Short Circuit study is never addressed. From our understanding, the only evidence that is required for this standard with respect to the review of information used for the Short Circuit study will be documentation of the ‘What’; no evidence is required of when it was followed.

Also, the word “review” in R1.1 is confusing and suggests going back in time. Suggest revised wording as follow: “A method to update the information required to develop new or revised Protection System settings.”

R1.2. The wording in the draft standard is confusing. Protection System settings are not affected by System changes. Suggest the following wording: “A review of the affected Protection System settings due to System changes as determined by the entity’s process.”

- It was mentioned in the Webinar on April 27, 2015 that System changes will reset baseline for Fault current studies. If this is the case, then it should be made clear in the standard.

- Proving system changes will be onerous. The rationale box for R1.2 is open ended and may leave the impression that every change, even minor ones, will be considered a System change and be subject to an audit. The standard should better define “System changes.”

R1.3. The last part of the description for “Periodic Fault current studies” is confusing. Suggest the wording be changed to the following: “… at the bus under study, and this Fault Current analysis evaluated in a time interval not to exceed six calendar years, or”

With regard to the discussion on R1.1.3 at the Webinar on April 27, 2015, it was stated that once the standard is adopted Utilities have 12 months to establish their fault current baseline, if using the Periodic Fault Current Study method or 6 years to perform their next Periodic review of Protection System settings if using that method of compliance. Those time frames should be spelled out in the document, especially the 12 months because it does not appear anywhere. Perhaps the best place for this is in the Implementation Plan.

Regarding Part 1.3, the first bullet, if the entity identifies a Fault current change greater than 15 percent, the periodic review should apply only to those buses identified as having a 15 percent or greater deviation in Fault current in the study and the connected buses one station away from those buses. Footnote 1 can be revised to:

Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults. For buses where the Fault current changed by 15 percent or greater, the Protection Systems will be those applied at the bus with the change in Fault current, and connected stations one bus away.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

Parts 1.1 through 1.4 have nothing to do with coordination with neighbors as previously covered by PRC-001 R3 and R4. They describe an internal process for protection design that is outside the scope of coordination with neighbors. Delete Parts 1.1 through 1.4.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: No

Answer Comment:

More clarification would be helpful concerning the term "entity-designated Protection System settings". It appears that these settings that are considered to be susceptible to fault current changes. Providing a listing of susceptible Protection System setting types applicable to the GO, TO and DP would insure that nothing is missed in the review.

Document Name:

Likes: 0

Dislikes: 0

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: No

Answer Comment:

See comments is question #4.

Document Name:

Likes: 2 Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4, James McFall, Modest
Colorado Springs Utilities, 3, Morgan Charles

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

While ATC agrees with the elements of a successful coordination process, we do not agree with the overall approach to the draft standard. It appears to be missing an element that incorporates a feedback loop to measure improvement.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

We generally agree, but we have concerns with the Parts themselves, as explained in #3 and #4 below.

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer: No

Answer Comment:

I do not feel that 1.5.2 is necessary to demonstrate coordination. Could be aligned with 1.5.3 and state simply "Verify that no coordination issues were identified....

In adition, not sure that 1.2 or 1.4 add value to the standard as they should be covered in 1.3.

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer: Yes

Answer Comment:

We generally agree, but we have concerns with the Parts themselves, as explained in #3 and #4 below.

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: No

Answer Comment:

Generally the parts 1.1 to 1.4 are essential elements for successful coordination. Part 1.5 creates unnecessary complications when phasing in projects or dealing with other entities that are not responsive in a timely fashion. Part 1.5 should be deleted since it can implicate a utility that is dealing with slow to respond interconnecting neighbors. There are utilities that will respond but may not respond in a timely manner. This puts all entities unfairly under scrutiny. If Part 1.4 is followed then 1.5 is not needed. This will eliminate implicating the responsible entity when dealing with slow to respond interconnecting neighbors and avoid tracking complex timelines with multiphase projects that may not have simple implementation dates. One scenario that can cause concern can be with generator owners that may not have their own engineering staff but must hire external staff if a coordination study is required. This process issue is not always under the control of the requesting entity and can create some issues with part 1.4 as well. In this sense it is a good thing if we can show seeking concurrence is acceptable for compliance even if we cannot show a response to a request.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: No

Answer Comment:

Refer to the MRO NSRF comments.

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

We agree with Parts 1.2, 1.3 and 1.5 of Requirement R1, but disagree with Parts 1.1 and 1.4.

Part 1.1 is not results-based; it is overly prescriptive and an inherent and necessary element for developing new or revised Protection System settings. We suggest removing Part 1.1 as it does not any value to Requirement R1.

R1.2. The current wording in the draft standard is confusing. We would suggest the following alternative wording: "A review of the affected Protection System settings due to System changes as determined by the entity's process."

- The study should clearly mention that System changes will reset the baseline for future Fault current studies.

- The rationale box for R1.2 is open ended and leaves the impression that every change, even minor ones, will be considered a System change and be subject to an audit. The standard should better define "System changes."

Part 1.4 is unclear and unnecessary. It is unclear as to what constitutes a "quality review" (QR), and how is it measured. Furthermore, it is not necessary to perform any QR. If the intent is to have this included in the process document to ensure new or revised protection system settings are properly coordinated, then this part should be revised to say, e.g.:

1.4 A check list to verify that the development of the new or revised protection system settings is coordinated among affected entities and that the proposed settings can achieve the intent of fault clearing prior to implementation.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: No

Answer Comment:

Entergy is concerned with elements of Parts 1.1 through 1.5 of Requirement R1.

Entergy is concerned that requirement R.1.3 does not adequately identify the methodology for establishing “baseline Fault current values.” Entergy would suggest the inclusion in requirement R1.3 of additional language on baseline Fault current values from bottom of page 13 and top of page 14 in the Supplemental Material document, as follows:

The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect. These baseline Fault current values can be at the bus level or at the individual Element level. When performing the periodic Fault current comparison, the entity would continue to compare actual Fault current values gathered during the review against the originally established baseline values until a condition occurs that necessitates the establishment of a new baseline.

Entergy disagrees with the inclusion of the language “prior to implementation” in Requirement R1.5.3 without a means to compel a timely response to the request for coordination . Requirement R1.5.3 provides as follows:

1.5.3. Verify that any identified coordination issue(s) associated with proposed Protection System settings for the associated Elements are addressed prior to implementation.

Based on experience, there are situations in which a Transmission Owner has submitted relay settings information to a coordinating party and the coordinating party has not responded or is incapable of assessing the impact of the change being coordinated. A lack of coordinating party response puts the Transmission Owner at risk of non-compliance with Requirement 1.5.3. Entergy recommends that Requirement 1.5.3 be revised to (1) require the coordinating party to respond to Transmission Owner within thirty (30) days after receipt of notification of proposed Protection System settings, provided that in the event of an Emergency, the coordinating party shall be required to respond to Transmission Owner as soon as practicable under the circumstances, and (2) in the event the coordinating party does not respond to the Transmission Owner's request for coordination in a timely manner, permit the Transmission Owner to assess and implement Protection System settings without acknowledgement from the coordinating party, subject to the requirement that the Transmission Owner provide prior notice to the coordinating party of its intent to implement its proposed Protection System settings..

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer: No

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.

.

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: No

Answer Comment:

GTC is in support of the SERC Comments:

While the SERC PCS agrees that PRC-027 is needed, and with the methodology within draft 5, the following items must be clarified for us to support it:

1) In R1 1.2 replace '…affected by System changes' with '…affected by Bulk Electric System changes' because the NERC Glossary 'System' definition includes distribution. NERC BES Definition phase 2 process is very rigorous and includes the Elements of significance in this coordination work.

2) R1 1.3 Footnote 1 and the concept of excluding 'entity-designated' Protection System settings is troublesome. The SDT explained that footnotes are enforceable in their 4/27/2015 Webinar, and that entities will have to justify such designations. R1 1.3 Footnote 1 text should be moved into the body of the requirement, eliminating the footnote, and clarity be given on what entities would need to do to justify the Protection Systems they are designating.

3) The existing Protection System settings have been and are already coordinated. We agree with the SDT 4/27/2015 Webinar statement that PRC-027 'draws a line in the sand and goes forward from there.' Please include a statement somewhere in the R1 Rationale that memorializes the validity of

existing Protection System settings as a baseline. We recommend including this statement in the R1 part 1.3 first bullet,

Periodic Fault current studies, rationale. ‘Protection System settings existing when the Fault Current baseline is established are accepted as being coordinated consistent with the Purpose of this standard. This acknowledges that the vast majority of entities have a long history and much experience coordinating their Protection Systems. On the other hand, if an entity is unable or unwilling to make this assertion, then that entity needs to explain the second bullet, *Periodic review of Protection System settings,* in its R1 process is its means of proving coordination of existing settings.’

4) In some companies the same protective relaying group performs coordination work for separate functional entities, so the R1 1.5 communication is often in the protection setting notes themselves. Please add ‘The drafting team also recognizes there are situations where the same protective relaying group performs coordination work for separate functional entities, and in such cases the R1 Part 1.5 communication is handled via internal written documentation.’ We suggest adding in the Supplemental Material on page 15 just above Requirement R2.

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer: Yes

Answer Comment:

PHI agrees that the information identified in parts 1.1 through 1.5 of Requirement R1 cover the essential elements needed to develop and ensure coordination of BES protective relaying schemes.

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

CSU agrees with SMUD's Comments concerning a potentially more effective approach to PRC-027.

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer: Yes

Answer Comment:

Part 1.5 requires that separate functional entities communicate their proposed Protection System settings with other functional entities. Should there be a proposed time limit to get a response from the other entity to ensure that there are no delays in addressing coordination issues prior to implementation?

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

R1.5 remains ambiguous in terms of which entities are obligated to perform the tasks, and under which circumstances. Is the intent, as written, that it only applies where interconnected Facilities do not have the same ownership? Is the applicability based on the functional entity category irrespective of Facility ownership (i.e., to ensure intra-company communications)? The requirement needs to be revised to provide absolutely certainly in terms of which entities have the obligations.

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

While the SERC PCS agrees that PRC-027 is needed, and with the methodology within draft 5, the following items must be clarified for us to support it:

1) In R1 1.2 replace '…affected by System changes' with '…affected by Bulk Electric System changes' because the NERC Glossary 'System' definition includes distribution. NERC BES Definition phase 2 process is very rigorous and includes the Elements of significance in this coordination work.

2) R1 1.3 Footnote 1 and the concept of excluding 'entity-designated' Protection System settings is troublesome. The SDT explained that footnotes are enforceable in their 4/27/2015 Webinar, and that entities will have to justify such designations. R1 1.3 Footnote 1 text should be moved into the body of the requirement, eliminating the footnote, and clarity be given on what entities would need to do to justify the Protection Systems they are designating.

3) The existing Protection System settings have been and are already coordinated. We agree with the SDT 4/27/2015 Webinar statement that PRC-027

'draws a line in the sand and goes forward from there.' Please include a statement somewhere in the R1 Rationale that memorializes the validity of existing Protection System settings as a baseline. We recommend including this statement in the R1 part 1.3 first bullet, *Periodic Fault current studies,* rationale. 'Protection System settings existing when the Fault Current baseline is established are accepted as being coordinated consistent with the Purpose of this standard. This acknowledges that the vast majority of entities have a long history and much experience coordinating their Protection Systems. On the other hand, if an entity is unable or unwilling to make this assertion, then that entity needs to explain the second bullet, *Periodic review of Protection System settings,* in its R1 process is its means of proving coordination of existing settings.'

4) In some companies the same protective relaying group performs coordination work for separate functional entities, so the R1 1.5 communication is often in the protection setting notes themselves. Please add 'The drafting team also recognizes there are situations where the same protective relaying group performs coordination work for separate functional entities, and in such cases the R1 Part 1.5 communication is handled via internal written documentation.' We suggest adding in the Supplemental Material on page 15 just above Requirement R2.

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

While the SERC PCS agrees that PRC-027 is needed, and with the methodology within draft 5, the following items must be clarified for us to support it:

1) In R1 1.2 replace '…affected by System changes' with '…affected by Bulk Electric System changes' because the NERC Glossary 'System' definition includes distribution. NERC BES Definition phase 2 process is very rigorous and includes the Elements of significance in this coordination work.

2) R1 1.3 Footnote 1 and the concept of excluding 'entity-designated' Protection System settings is troublesome. The SDT explained that footnotes are enforceable in their 4/27/2015 Webinar, and that entities will have to justify such designations. R1 1.3 Footnote 1 text should be moved into the body of the requirement, eliminating the footnote, and clarity be given on what entities would need to do to justify the Protection Systems they are designating.

3) The existing Protection System settings have been and are already coordinated. We agree with the SDT 4/27/2015 Webinar statement that PRC-027 'draws a line in the sand and goes forward from there.' Please include a statement somewhere in the R1 Rationale that memorializes the validity of existing Protection System settings as a baseline. We recommend including this statement in the R1 part 1.3 first bullet, *Periodic Fault current studies,* rationale. 'Protection System settings existing when the Fault Current baseline is established are accepted as being coordinated consistent with the Purpose of this standard. This acknowledges that the vast majority of entities have a long history and much experience coordinating their Protection Systems. On the other hand, if an entity is unable or unwilling to make this assertion, then that entity needs to explain the second bullet, *Periodic review of Protection System settings,* in its R1 process is its means of proving coordination of existing settings.'

4) In some companies the same protective relaying group performs coordination work for separate functional entities, so the R1 1.5 communication is

often in the protection setting notes themselves. Please add ‘The drafting team also recognizes there are situations where the same protective relaying group performs coordination work for separate functional entities, and in such cases the R1 Part 1.5 communication is handled via internal written documentation.’ We suggest adding in the Supplemental Material on page 15 just above Requirement R2.

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We agree with Parts 1.2, 1.3 and 1.5 of Requirement R1, but disagree with Parts 1.1 and 1.4.

Part 1.1 is not results-based; it is overly prescriptive and an inherent and necessary element for developing new or revised Protection System settings. We suggest to remove it as it does not add any value to Requirement R1.

Part 1.4 is unclear and unnecessary. It is unclear as to what constitutes a “quality review” as this term is confused with that part of the standards development process with the same name. If the intent is to have this included in the process document to ensure new or revised protection system settings are properly coordinated, then this part should be revised to say, e.g.:

1.4 A check list to verify that the development of the new or revised protection system settings is coordinated among affected entities and that the proposed settings can achieve the intent of fault clearing prior to implementation.

Note - These SRC comments represent a consensus of the ISOs/RTOs with the exception of ERCOT.

Document Name:

Likes: 0

Dislikes: 0

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christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. agrees with NPCC on the following.:

1) Under R1.1, “A method to review and update the information required to develop new or revised Protection System settings” requires entities to develop a process to review information used in two studies: Short Circuit study and Protective Device Coordination study. The ‘When’ for the review of information used in the Short Circuit study has not been addressed. R1.1. addresses the ‘What’ but does not address the ‘When’. The ‘When’ for the review of the information used in the Protective Device Coordination study is addressed in R1.2 and R1.3. Therefore, the only evidence that is required with respect to the review of information used for the Short Circuit study will be documentation of the ‘What’; no evidence is required of “When” it was followed.

2) Further, in R1.1, the word “review” suggests going back in time. It is suggested that the wording is revised to read as follows: “A method to update the information required to develop new or revised Protection System settings.”

3) The wording for R1.2 is unclear. Protection System settings are not affected by System changes. It is suggested that the following wording be considered instead: “A review of the affected Protection System settings due to System changes as determined by the entity’s process.”

4) It was mentioned during the Webinar on April 27, 2015 that System changes will reset the baseline for Fault current studies. If this is the case, it should be explicitly stated in the standard.

5)In the rationale box for R1, Part 1.2 is open-ended and may leave the impression that every change, even minor ones, will be considered a System change and be subject to an audit. Therefore, the standard should specifically define “System changes.”

6) The last part of the description in R1.3 for “Periodic Fault current studies” is unclear. It is suggested that the wording under the first bullet in R1.3 be changed to read the following: “… at the bus under study, and this

	Fault Current analysis be evaluated at a time interval not to exceed six calendar years, or" 7) With regard to the discussion on R1.3 at the Webinar held on April 27, 2015, it was stated that once the standard is adopted, utilities would be given 12 months to establish their fault current baseline, if using the Periodic Fault Current Study method, or 6 years to perform their next Periodic review of Protection System settings if using the method of compliance which requires a Periodic review. These time frames should be spelled out in the document; in particular, the 12 months given to establish a fault current baseline, as it is not stated in the standard. These dates should be stated in the Implementation Plan as well.
Document Name:	
Likes:	0
Dislikes:	0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Chris Scanlon - Exelon - 1 -

Selected Answer: No

Answer Comment:

Please clarify R1.3. We believe the SDT intends to say that an entity must have a process to review protection system settings:

- First Bullet- Review Bus fault currents at least every six years. If review indicates that fault current has increased to 15% or more than baseline, then perform a settings review for relays associated with that bus.

- Second Bullet- Review relay settings at least every six years

- Third Bullet- Some combination of first two bullets.

If our understanding is correct, we propose a minor clarification to the first bullet in R1.3

· **Periodic Fault current studies:** 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 the bus under study. The fault current must be evaluated periodically with the time interval not to exceed 6 years.

As a Generator, Part 1.3 of requirement R1 needs to be defined clearly from the GOs viewpoint stating if contribution by GO increases by 15%. It talks about a fault current at a Bus which is more appropriate for TO. GO's current contribution increases only when the Generators and Main Power transformers are replaced with machines with lower impedances. So the requirements should be tied with that rather than on a certain time.

Part 1.4 - Agree

Part 1.5.3: We remain concerned with the requirement as written. 1.5.3 is open to interpretation regarding how an entity addresses an identified coordination issue prior to implementation. As noted in the Supplemental Material, differences in Protection Philosophy, the actual risk of an unmitigated issue or the timing of a mitigation action are all areas where entities may disagree before the implementation of new settings. A change to 1.5.2 indicating that the communication between the coordinating entities should include the entities proposal for what or if any action they intend to take respecting an identified issue would be sufficient. This is consistent with the Supplemental Material explanation for Part 1.5.2

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer: No

Answer Comment: See Exelon commnets as submitted by C Scanlon

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: No

Answer Comment:

1. Ambiguity exists with respect to what "coordination" is being addressed. This should be explicitly clarified. Part 1.5 addresses coordination of information with others necessary to determine proper settings on BES Protection Systems for facilities owned by two different entities, which is consistent with the context of the existing standard. However, Parts 1.1-1.4 pertain to an entity's internal process for developing, reviewing, and validating settings, which is not considered in the current standard and is not in the same coordination context as Part 1.5. As presented, parts 1.1 through 1.4 exceeds "what needs to be done" and ventures into the "how it needs to be done" which runs counter to the intent of the NERC standards and risk-based requirements. Parts 1.1 – 1.4 should be rewritten in a manner similar to Part 1.5 as follows:

Each Transmission Owner, Generator Owner, and Distribution Owner shall implement a documented process for developing and installing coordinated settings for its Protection Systems for BES Elements associated with solely-owned Facilities to ensure the Protection Systems operate in the intended sequence during Faults.

This approach would also result in the elimination of one of the requirements as the implementation piece is captured with the documented process aspect.

Although we wish Requirement R1 to be rewritten as discussed above, we have the following additional comments with regards to the language of the requirements as currently proposed:

2. To make the existing requirement language clearer, Requirement R1 should be amended to state "……develop settings for its BES Protection Systems to ensure they operate in the intended sequence……"

3. Soon to be implemented MOD-032-1 requires Transmission Owners (TO) and Generator Owners (GO) in R2 to submit short-circuit modeling data to its Transmission Planner (TP) and Planning Coordinator (PC) on an annual cycle. The PC and TP then use this information to develop system models for use in current year and future year planning studies. As such, the TP and PC would have the most accurate composite short circuit model of the system at a point a time. PRC-027-1 does not acknowledge the significant role that the TP and PC could positively play in the review of short circuit fault current studies that is contemplated by Part 1.2 and 1.3. To this end, the TP and PC should be added as functional entities to whom this standard applies. The TP and PC should establish the baseline short circuit case annually and perform a comparison to identify buses whose fault currents have deviated by more than a certain percentage. This would then trigger a settings and coordination review by the TOs and GOs.

This is a more proactive approach that the possibility of looking at settings once every six years as currently posited by the standards. With the changes in generation due to coal unit retirements and the influx of new gas units across the system, there is a real possibility of more variation in fault current levels. An annual identification of significant deviations in fault current levels is a more effective method to achieve the desired outcome using the TP and PC as an applicable entity in this process. This would also address in part the impact of System changes as identified in Part 1.2 of the proposed standard as well.

4. What is the basis for the choice of 15% as the threshold for reviewing settings? If settings were perpetually off by 14.8%, what is the impact on intended Protection System operation? Is the risk imparted to the BES of this setting inaccuracy consistent for all Protection Systems and at all voltage levels? Is there a technical basis for this choice that contemplates risk to the BES?

5. For Part 1.3, PRC-027 intended to provide flexibility to cover the various relay applications an entity might have. However, similar to what was done in PRC-023, the team should be able to identify a non-exhaustive list of known relay applications that should be included in the review versus those that would not be.

6. The term "quality review" is ambiguous and should be replaced with a more precise description of the requirement. Suggest that the language be changed to:

"Perform an additional manual or automated technical review of the settings prior to implementation. If done manually, the individual(s) performing the additional review should not have been involved in the determination of the initial settings."

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: No

Answer Comment:

Comments: The requirements assume protective elements are primarily impacted by changes in fault current. For utilities, particularly in the west, that use impedance-based protection, the language in the standard may be deficient to cover parts of the protection system are not impacted by changes in Fault current. As such, the drafting team should consider how to address entities with schemes that are indifferent to fault current changes (i.e. line differential and impedance-based step distance). Perhaps these entities should be provided an exemption that only requires review when the zone is directly impacted. If these are not exempted, the Drafting Team should consider whether there is a technical basis for requiring a 6-year review on elements that are not impacted by changes in fault current conditions.

Review of distance settings and differential settings is not necessary until changes in the system require it. Current-only items, such as instantaneous over-currents, are the only items that need oversight related to changes that influence the fault study.

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

These general comments are based on two interpretations of Requirement R1:

1. Assuming that the intent is that the ‘Process’ identified in R1 applies to all new or changes to existing Protection System setting, we observe the following:

a. The inclusion of R1.2 tends to indicate that only those Protection System settings affected by System changes are covered.

b. The inclusion of the footnote in R1.3 tends to indicate that only ‘entity designated’ Protection Systems are included. The footnote also states ‘entities will indicate’ which makes this a requirement. This should be as a requirement not in a footnote. We question the advisability of having it buried in a footnote when an auditor will be expected to ask for it.

As such, if the intent is that entities shall follow their process for ‘all new or changes to existing Protection Systems settings’, then this language should be included in the main part of R1. If this is the intent, our opinion is the R1.2 and the footnote can be removed from the standard.

The following are specific:

	R1: add ‘all new or changes to existing’ R1.1: Agree R1.2: Disagree: we believe this requirement is duplicative to the intent of ‘all new or changes to existing’ R1.3: Agree, however, we believe the ‘entity designated’ defeats the concept of ‘all new or changes to existing’ and if it remains, it creates a reliability gap. R1.4: Agree R1.5: Agree 2. Assuming that the intent is that the ‘Process’ identified in R1 applies only to those protection systems identified in R1.2 and/or the ‘entity designated’ Protection Systems identified in the footnote, then these ‘applicable’ Protection Systems should be included in the Applicability of the Standard and R1.2 and the footnote should be removed from the standard. If this is the intent, we feel that the SDT has created a ‘reliability gap’ in that all new or changes to existing Protection Systems are not required to follow the other sub-requirements, such as reviewing the model and having a quality control check. Additionally it does not require entities to review settings on such things as current differential line protection, bus diff, bank diff, etc. schemes, thus allowing legacy incorrect settings to go undetected.
Document Name:	
Likes:	0
Dislikes:	0

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

Selected Answer: Yes

Answer Comment:

BPA requests that the SDT provide guidance or solutions available to meet R1.1.4, e.g., automated checking programs for the quality review.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Requirement R1 should be revised to read "…establish a process or processes" instead of "a process." An Entity may choose to implement a separate process for each Part.

Part 1.1. "A method to review and update the information required to develop new or revised Protection System settings." requires entities to develop a process that includes a method to review information used in two studies: Short Circuit Study and Protective Device Coordination Study. Part 1.1 only addresses the 'what' but does not address the 'when'. The 'when' for the review of the information used in the Protective Device Coordination Study is addressed in Parts 1.2 and 1.3. The 'when' for the review of information used in the Short Circuit Study is never addressed. The only evidence that is required for this standard with respect to the review of information used for the Short Circuit Study will be documentation of the 'what'; no evidence is required of 'when' it was followed. Also, Part 1.1 is not results-based; it is overly prescriptive and an inherent and necessary element for developing new or revised Protection System settings. We suggest it be removed as it does not add any value to Requirement R1. If the drafting team decides that Part 1.1 is necessary, then additional clarification is recommended regarding the scope of information to be reviewed and to what extent the review needs to be performed. Alternative wording could also be considered such as, "A procedure to track changes to the primary system and associated information required to develop new or revised Protection System settings."

It was mentioned in the April 27, 2015 Webinar that System changes will reset the baseline for Fault current studies. If that is the case, then it should be made clear in the standard. Proving system changes will be onerous. In the Rationale Box for Requirement R1, the section referring to Part 1.2 is open ended and may leave the impression that every change, even minor ones, will be considered a System change. The standard should better define "System changes."

Part 1.3. The last part of the description for "Periodic Fault current studies" is confusing. Suggest the wording be changed to the following: "… at the bus under study, and this Fault Current analysis evaluated in a time interval not to exceed six calendar years, or"

In the Rationale for Requirement R1, under Part 1.3, in the second paragraph there is the sentence "To minimize this risk, the drafting team chose a maximum Fault current deviation of 15 percent." Yet in Part 1.3 itself it says "A 15 percent or greater deviation in Fault current…" Suggest adding or removing the words "or greater" to reflect the intent. The Rationale and Part should be consistent.

Regarding the first bullet of Part 1.3, if the entity identifies a Fault current change equal to or greater than 15 percent, the periodic review should apply only to those buses identified as having a 15 percent or greater deviation in Fault current in the study and the connected buses one station away from those buses. Footnote 1 can be revised to:

Based on the Protection System design and/or susceptibility to changes in Fault current, applicable entities (Transmission Owners, Generator Owners, and Distribution Providers) will designate what Protection Systems must be included in the review(s) to ensure these Protection Systems continue to operate in the intended sequence during Faults. For buses where the Fault current changed by 15 percent or greater the Protection Systems will be those applied at the bus with the change in Fault current, and connected stations one bus away.

Part 1.4 is unclear. It is unclear as to what constitutes a "quality review", and how is it measured. It is not necessary to perform any QR. If the intent is to have this included in the process document to ensure new or revised protection system settings are properly coordinated, then this part should be revised to say, e.g.:

1.4 A check list to verify that the development of the new or revised protection system settings is coordinated among affected entities and that the proposed settings can achieve the intent of fault clearing prior to implementation.

In sub-Part 1.5.1 suggest changing "other functional entities" to "impacted (or affected) functional entities".

Requirement R2 requires the Entity to implement the R1 process. The plainest reading of the requirement only requires the process to be implemented. Suggest that R1 and R2 be combined and formatted into the CIP table format. R1 becomes “establish and implement a process or processes” and then in a table format list each part and in the adjoining column the measures to demonstrate compliance.

With regard to the discussion on sub-Part 1.3.1 at the Webinar on April 27, 2015, it was stated that once the standard is adopted utilities have 12 months to establish their fault current baseline if using the Periodic Fault Current Study method, or 6 years to perform their next Periodic review of Protection System settings if using that method of compliance. Those time frames should be spelled out in the document, especially the 12 months because it does not appear anywhere. Perhaps the best place for this is in the Implementation Plan.

The existing requirement R3 in PRC-001-1.1 calls for coordination between Generator Operators and Transmission Operators with the Host Balancing Authority:

R3. A Generator Operator or Transmission Operator shall coordinate new protective systems and changes as follows.

R3.1. Each Generator Operator shall coordinate all new protective systems and all protective system changes with its Transmission Operator and Host Balancing Authority.

R3.2. Each Transmission Operator shall coordinate all new protective systems and all protective system changes with neighboring T Transmission Operators and Balancing Authorities.

While the language regarding coordination by the Host Balancing Authority is not concise, the Host Balancing Authority should be made aware of relaying changes. PRC-027-1 sub-Parts 1.5.1 and 1.5.2 should be revised as follows:

1.5.1. Communicate the proposed Protection System settings with the other functional entities and the Host Balancing Authority.

1.5.2. Review proposed Protection System settings provided by other functional entities and the Host Balancing Authority, and respond regarding the proposed settings. The response should identify any coordination issue(s) or affirm that no coordination issue(s) were identified.

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

FMPA has previously commented that the speed at which faults are cleared is very important to reliability, and recommends the SDT consider adding a part that requires review of Protection System settings with regard to critical clearing time.

Regarding Part 1.3, either require the use of periodic Fault current studies for specified types of Protection Systems, or leave the option out. FMPA understands the importance of considering changes in Fault current when coordinating Protection Systems, but does not see the reliability benefit of providing options in Part 1.3. From a compliance perspective, it is simpler to demonstrate compliance by always choosing the time-based methodology. As presently worded, the Fault current-based option does not add any benefit for either reliability or compliance since it is not required to be used and defaults to a six year review of settings. Also, it is not clear what conditions necessitate the establishment of a new baseline. Some language from the Option 1 discussion in the supporting material describing how the baseline is determined should be incorporated into the Requirement language.

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

TVA appreciates the efforts of the Project 2007-06 SDT in developing Draft 5 of PRC-027-1. While TVA agrees with R1 and its associated sub-parts, the following comments are offered as possible improvements:

1) In R1, Part 1.2, replace "…affected by System changes" with "…affected by **Bulk Electric System** changes" because the NERC Glossary definition of "System" includes 'distribution components'.

2) R1, Part 1.3, Footnote 1 - The SDT explained that footnotes are enforceable in the 4/27/2015 project webinar, and that entities will have to justify their PRC-027 designation criteria. We recommend the SDT consider eliminating Footnote 1, and adopt an "Attachment A" approach similar to the PRC-023 standard. Doing so would tend to bring the industry to a more common understanding of the types of Protection System devices that are intended to detect Faults and initiate an isolating action, and reduce the opportunity for "gaming" the standard.

3) We agree with the SDT 4/27/2015 Webinar statement that PRC-027 "draws a line in the sand and goes forward from there." The presumption should be that existing Protection System settings have already been coordinated. We suggest adding a statement in the R1 Rationale block that memorializes the validity of existing Protection System settings as a baseline. We recommend including this statement in the R1, Part 1.3, Periodic Fault current studies rationale -

	“Protection System settings existing when the Fault Current baseline is established are accepted as being coordinated consistent with the Purpose of this standard. This acknowledges that the vast majority of entities have a long history and much experience coordinating their Protection Systems.” 4) In companies where a single protective relaying group performs coordination work for separate functional entities within the company, the R1, part 1.5.1 communication is often captured in the protection setting notes themselves. Please add “The drafting team also recognizes there are situations where the same protective relaying group performs coordination work for separate functional entities within the same company, and in such cases the R1, Part 1.5.1 communication is handled via internal written documentation.” We suggest adding this statement in the Supplemental Material on page 15 just above Requirement R2.
Document Name:	
Likes:	0
Dislikes:	0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

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

Selected Answer: No

Answer Comment:

Texas RE recommends including language in R1.5.1 for entities to communicate changes or settings before they are implemented. Texas RE suggests that six years is too long of a time period between a studies of Fault currents.

In general the requirements are sound but it seems the rationale behind the timing may be inconsistent with other standards such as TPL-001-4 (an annual short circuit analysis with caveats). In essence, an entity cannot tell if there is a 15% or greater deviation in Fault current without doing a study and 6 years appears to be an inordinate amount of time to lapse. Also, the “entity designated” language allows for entities to not conduct reviews if no “settings” are “designated” which defeats the reliability aspects of this standard. Footnote 1 indicates “Protection Systems” will be included but the text of 1.3 indicates which “Protection System settings”. Is the intent to designate a particular setting which then, by default, designates the Protection System where the setting is applicable? It would be beneficial to clarify the footnote.

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

Reclamation believes that the draft PRC-027-1 is a major improvement over the existing ambiguous language in PRC-001-1.1 regarding relay settings coordination.

Reclamation recommends updating R1.2 to reference “Protection System changes” rather than “System changes” for consistency.

Reclamation suggests that the “Supplemental Material” for Part 1.3 be updated to state that “non-fault clearing protection other than covered under PRC-019 which do not operate for faults, but are in place to protect equipment, does not require coordination between functional entities. Examples of such protection include differential relays, volts per hertz, loss-of-field, negative sequence current, stator ground, overvoltage, under frequency and out-of-step relays designed to protect generators rather than to operate for faults on the transmission system.”

Reclamation also suggests that R1.5 and its subrequirements be updated to refer to “Facilities owned by separate registered entities,” so it is clear that R1.5 refers to settings coordination between separately owned facilities. Reclamation believes that the quality review of settings required under R1.4 will assure appropriate coordination of settings for Protection Systems at adjacent facilities owned by one registered entity acting as GO and TO. Reclamation suggests that the drafting team add a footnote to R1.5 to clarify that coordination of relay settings owned by one registered entity operating as two functional entities (e.g., GO and TO) are covered by the quality review process in R1.4. Reclamation also suggests that the “Supplemental Material” section for Part 1.4 be updated to address this issue.

Finally, Reclamation recommends that the “Supplemental Material” section be renamed the “Guidelines and Technical Basis” section because this appears to be the intent of the section and for consistency with other standards.

Document Name: Reclamation PRC-027-1_Comments_05142015.docx

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment:

1) In addition to our own comments, Ameren adopts the SERC PCS comments by reference. (Note: SERC Reliability Corp may actually be the submitting entity for the SERC Protection and Control Subcommittee comments.)

2) While Ameren agrees that PRC-027 is needed (we have voted in favor of previous drafts), the following items must be clarified before Ameren can support its new form: See SERC PCS Question 1 comments 1, 2, 3, and 4; SERC Question 2 comment 1; and SERC Question 4 comments 3 and 4; and Ameren specific comment 3 below.

3) We believe that the intent for R1 part 1.2 is for the entity to review Protection System settings *directly and/or significantly* affected by the changes in Part 1.1, and that Part 1.3 will capture the incremental (or less significant) changes that accumulate over time. If so, we feel this is unclear and recommend moving the similar examples from the Part 1.2 rationale to the Part 1.1 rationale and revising Part 1.2 and its rationale as follows:

a) Part 1.2: "A review of Protection System settings directly and/or significantly affected by changes identified in Part 1.1."

b) Part 1.2 Rationale: "Reviewing the affected Protection System settings when significant changes to the information identified in Part 1.1 occur maintains coordination. For example if a new BES Element (transmission line or generator) is added, Protection System settings directly protecting that new Element must be developed. And Protection System settings on BES Elements adjacent to the new Element may well be significantly affected and therefore should be reviewed as well. On the other hand, a very small change to one Element's impedance may not by itself cause a significant enough change to trigger this Part 1.2 review; the accumulation of such minor changes will be captured via Part 1.3 of the process."

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We question the reliability value of creating an administrative requirement that will undoubtedly be rated as a high risk based on the latest risk elements documentation. Utilities have always installed and coordinated Protection Systems to protect the safety of the general public, to protect equipment from damage, to improve reliability, and to provide good customer service. If they did not do this, they would not stay in business very long and would be subject to countless sanctions and fines from regulatory agencies. Utilities already have Protection System coordination processes in place whether formally documented or simply followed by the professional engineering staff. Furthermore, professional engineering and IEEE standards already require the coordination of protection systems, which supports that the proposed Requirement R1 is not needed.

We simply do not see how adding this standard further enhances reliability. There is no evidence that there is a widespread lack of Protection System coordination. As a result, the proposed standard could actually decrease reliability by detracting from the reliability mission to focus on paperwork. There does not appear to be any explanation to how this standard will improve reliability over what industry is already doing. If Protection System engineers are further distracted from their reliability mission by additional needless paperwork, we fear that reliability will suffer.

More specifically, we are concerned that Part 1.4 could be burdensome for small entities that may only have one Protection System engineer. How can such a small entity implement a quality review process that involves peer reviews? This could be quite costly to these entities, as they would be forced to hire consultants to conduct a peer review, which may only result in minimal reliability benefits.

We question why a Distribution Provider should be required to have a process for developing Protection Systems settings. Distribution Providers that have Protection Systems installed for detecting faults on the BES will only do so at the direction of the TO and this should be covered in the Facility connection requirements in the FAC standards. We suggest removing Distribution Provider.

The supplemental material needs to be clarified to state that the applicable entity has complete flexibility to use any combination based on any criteria not just limited to voltage or Protection System applications. The supplemental material appears to limit how both options in Part 1.3 can be combined in the standard. For instance, can an entity use one option for one bus and the other option for a different bus? Can they base it on zones of protection?

How Part 1.2 is different from Part 1.3 should be further clarified. Part 1.2 focuses on reviewing necessary Protection Systems settings based on System changes. The supplemental materials focus largely on system impedance changes. Since these would contribute to changes in fault currents, would Part 1.3 trigger the need to review these? Could Part 1.2 be combined with Part 1.3?

The drafting team should consider extending the periodic review in Part 1.3 beyond six years. The supplemental material indicates this period was selected to match the maintenance cycle for PRC-005 for relays. However, some relays (i.e. monitored) have longer maintenance cycles.

We recommend removing R1 from the standard, as a formal policy is not needed for coordination of Protection Systems. However, if the drafting team determines that the requirement must remain, we ask the team to revise the requirements to streamline the process, remove as much administrative paperwork as possible, and revise the sub-parts for clarity.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

AECI appreciates the flexibility afforded to industry with the process document based language of draft PRC-027-1. We agree that all elements in parts 1.1 through 1.5 are essential elements of a successfull coordination process with one small disagreement in part 1.2 that could be mitigated with two insertions of "significant" and "BES". Suggested langugage: "A review of Protection System settings affected by significant BES changes." First, the insertion of the word significant would more closely align with the SDT intent and rationale given. Second usage of BES would clearly indicate the scope of the standard, which is to coordinate protection system settings that are applicable to the BES.

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The phrase “System changes” as used in R1.2 is not a defined term and is only described by a set of examples in the Supplemental Material. While this arrangement may be sufficient for compliance audits, there remains a potential gap. There may be “System changes” that warrant a review of the protection system settings that are not included in the specific set of examples provided and could lead to an entity experiencing a change that does not trigger a review of protection system settings. We suggest the Supplemental Materials include the phrase “including, but not limited to” when providing a set of example “System changes”.

The use of the undefined phrase “quality review” in R1.4 and then seemingly defining that term in the Supplemental Material could lead to issues in interpretation of what is an “adequate” quality review. The SDT should review the guidance and rationale regarding what constitutes a quality review to ensure as much potential for mis-interpretation is minimized. We would suggest the removal of R1.4.

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

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

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer: No

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

We do not agree with Measure M1 as we do not agree with Parts 1.1 and 1.4.

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE	
Selected Answer:	Yes
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0
Robert Hirchak - Cleco Corporation - 6 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0
Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

See comments above.

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

Tacoma Power defers comments on the proposed measures until the industry comes to more agreement on the requirements.

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Please note that the CEA can ask for any evidence and the applicably entity can provide any evidence to assure compliance. Measures should support the Requirement. We have no issues with the Measures provided.

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Measures should be updated to reflect the changes made in the Requirements based on our responses to Question 1.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: No

Answer Comment:

Modify M1 to align with the deletion of R1.1 through R1.4. M2 OK.

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: No

Answer Comment:

M1 and M2 should clearly state what acceptable evidence is. The phrase "but is not limited to" can be interpreted to mean that more evidence may be required than stated.

Document Name:

Likes: 0

Dislikes: 0

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: No

Answer Comment: see comments in question #4.

Document Name:

Likes: 1 Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4, James McFall, Modest

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Regarding M2, what constitutes “implementation” may vary, depending upon the process developed in R1. See our comments in #3 below.

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer: Yes

Answer Comment:

I don't necessarily agree with the overall expansion of scope in this standard beyond interconnected elements, but the measures are appropriate if the scope is approved.

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer: No

Answer Comment:

Regarding M2, what constitutes “implementation” may vary, depending upon the process developed in R1. See our comments in #3 below.

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: No

Answer Comment:

There is a concern with M1 such that in order to demonstrate the required process is implemented that dated records must be provided. If the auditor can select any BES element internal to our system for review then we must show that it meets the latest process. This means we must have all internal locations updated such that they are ready for audit to the latest required process at the effective date since there is no implementation time line provided for R1. It seems R1 should also provide an initial time window in the implementation plan for the process to be created and implemented over time. For example, this time window could be 7-10 years since there may be many more internal lines (depending on voltages) and generation for a utility in comparison to say interconnecting 200kV lines with other utilities.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

We do not agree with Measure M1 as we do not agree with Parts 1.1 and 1.4.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: No

Answer Comment:

The requirements do not address the extent of system conditions that the intended tripping must be reviewed (Relay failure, battery failure, etc) and is therefore open to wide interpretation. During the recent webinar, it was stated the standard is only for primary protection not backup protection yet the language in the standard does not reflect this scope.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The GO is not in a position to identify this process for the BES.

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: No

Answer Comment:

GTC is in support of the SERC Comments:

1) Revise M2 so entities that choose the

Periodic Fault current studies bullet as their trigger for a review of existing Protection System settings are aware that they will need appropriate documentation. Please add ‘If the entity uses the *Periodic Fault current studies* method, acceptable evidence may include, but is not limited to, a list of each BES bus, its baseline Fault current, date of the baseline, its periodically reviewed Fault current, and the date of the review.' (Perhaps this instead belongs in the RSAW.)

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

CSU agrees with SMUD's Comments concerning a potentially more effective approach to PRC-027..

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

Revise M2 so entities that choose the *Periodic Fault current studies* bullet as their trigger for a review of existing Protection System settings are aware that they will need appropriate documentation. Please add 'If the entity uses the *Periodic Fault current studies* method, acceptable evidence may include, but is not limited to, a list of each BES bus, its baseline Fault current, date of the baseline, its periodically reviewed Fault current, and the date of the review.' (Perhaps this instead belongs in the RSAW.)

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

1) Revise M2 so entities that choose the *Periodic Fault current studies* bullet as their trigger for a review of existing Protection System settings are aware that they will need appropriate documentation. Please add 'If the entity uses the *Periodic Fault current studies* method, acceptable evidence may include, but is not limited to, a list of each BES bus, its baseline Fault current, date of the baseline, its periodically reviewed Fault current, and the date of the review.' (Perhaps this instead belongs in the RSAW.)

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We do not agree with Measure M1 as we do not agree with Parts 1.1 and 1.4.

Note - These SRC comments represent a consensus of the ISOs/RTOs with the exception of ERCOT.

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer: No

Answer Comment:

We would like to see more clarity around the measure for requirement R1. Requirement R1 has five subparts but measure M1 doesn't appear to adequately address each of these subparts (R1.1-R1.5). As is, measure M1's ambiguity leaves us unsure as to what evidence is required to adequately show compliance with requirement R1.

Document Name:

Likes: 2 OGE Energy - Oklahoma Gas and Electric Co., 1, Pyle Terri
OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: No

Answer Comment:

The measure for R1 and its subparts does not adequately address the expectations contained in the requirement. THere is no requirement to have a documented process per R1 but this certainly is the most forthright manner to achieve the reuqirement. Else, an entity will have to demonstrate for each setting how each subpart is demonstrated. Since R2 is the implementation piece, evidence of implementation is expected there. Absent a documented process document or perhaps a workflow to satsify R1, it is not clear how the evidence for R2 would be different from R1. It is also not clear without a process document or workflow how an entity would demonstrate that each process part was consistently addressed. In this regard and as offered in the comments, R1 and R2 could be combined into one requirement that speaks to "implementing a documented process".

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: No

Answer Comment:

Comments: The measures should be revised to speak directly to elements being impacted..

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

1. In discussions with various groups the measure for M1 appears to be confusion to some folks. The addition of dated records tends to lead them down the path, of implementing the plan. Perhaps a change to clearly state that what is expected is a dated policy that indicates the entity has established ….

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

We do not agree with Measure M1. Refer to our comments above regarding Parts 1.1 and 1.4.

M2 requires evidence that the process was implemented. To be specific this measure is not requiring the entity to retain evidence that each step of the process was implemented or that for each relay setting a package of information showing the protection system analysis, study files, communications with other Entities was executed. In comparison, PRC-005 requires an entity to maintain and retain evidence of the maintenance of protection systems; not to implement a maintenance program.

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Measures should indicate acceptable examples of evidence of compliance.

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

While TVA generally agrees with the proposed measures, the following comments are offered as possible improvements:

Since Requirement R1 emphasizes a periodic review of Protection System settings, we suggest the wording for Measure M1 be revised slightly to read "…a process to develop **and periodically review** settings…".

We suggest revising M2 so entities that choose the "Periodic Fault current studies" method as their trigger for a review of existing Protection System settings are aware that they will need appropriate documentation. Please add "If the entity uses the Periodic Fault current studies method, acceptable evidence may include, but is not limited to, a list of each BES bus, its baseline Fault current, date of the baseline, its periodically reviewed Fault current, and the date of the review." (If adopted, this would also need to be reflected in the RSAW.)

Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

Reclamation disagrees with the proposed measures because they do not adequately describe evidence of quality reviews required under R1.4 or evidence of coordination by separate functional entities required under R1.5.

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: No

Answer Comment:

See SERC PCS comments.

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The measures do not provide guidance regarding how compliance will be measured by a Compliance Enforcement Authority. The measures are so generic that a single measure could be written for both requirements and could be summed up as "evidence that demonstrates compliance with the requirement." According to the Standards Process Manual, a measure "provides identification of the evidence or types of evidence that may demonstrate compliance with the associated requirement." The measures in the current draft do not identify any specific evidence or types of evidence.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0

3. 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: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer: No

Answer Comment:

Please clarify when the process has to be implemented for the first time. It is not entirely clear. Maybe it is 6 years???? Also suggest a two year implementation period instead of one due to the complexity.

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer: No

Answer Comment:

There seems to be conflict with timelines, comparing the Standard itself to the Implementation Plan. R2.2 places a timeline for completion of 90 calendar days after the completion of the R1 assessment, and word has filtered down that WECC said that if the R1 assessment is completed prior to the effective date, the clock starts ticking on the R2.2 90 days. However, the implementation plan says that R2.2 has to be completed with 90 calendar days of the effective date of the Standard. That could be a very different end date for R2.2.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

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

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer: No

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.

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

See comments above.

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer: No

Answer Comment:

ICLP can only commit to providing an initial baseline of our Fault relay performance within a year of FERC’s approval if the scope is limited to our GO-TO interconnections. Otherwise, entities will need much more time to verify that every one of their relay systems react in the proper sequence in response to a Faults.

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

Unless an entity can reasonably demonstrate that they have documentation of existing coordination studies, there needs to be an implementation period during which coordination of applicable Protection System settings are initially documented. This documentation will serve as a baseline for Parts 1.2 and 1.3 of Requirement R1.

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

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

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer: No

Answer Comment:

12 months is a reasonable time to establish the process required in R1, but not sufficient time to implement the process as required in R2. A six calendar year time interval for R2 would be more reasonable and aligns with the interval stated in Part 1.3.

Document Name:

Likes: 0

Dislikes: 0

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: No

Answer Comment:

IBID

Document Name:

Likes: 0

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

An entity must be in compliance with the requirements of a standard on day 1. The Implementation Plan allows 12 months after approval of the standard for this to occur. If a process is completed per R1 within 12 months, an entity is compliant with R1. But what constitutes compliance with “implementing the process established in accordance with requirement R1”? For example, if an entity’s process adopts the a six-year review cycle of its Protection System setting as permitted in the second bullet in Part 1.3, what would it be implementing on day 1?

The team should consider requiring an entity-specific implementation timeline to be included in the process developed in R1, with R2 stating that an entity shall implement its R1 process in accordance with its timeline in R2.

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer: No

Answer Comment:

An entity must be in compliance with the requirements of a standard on day 1. The Implementation Plan allows 12 months after approval of the standard for this to occur. If a process is completed per R1 within 12 months, an entity is compliant with R1. But what constitutes compliance with "implementing the process established in accordance with requirement R1"? For example, if an entity's process adopts the a six-year review cycle of its Protection System setting as permitted in the second bullet in Part 1.3, what would it be implementing on day 1?

The team should consider requiring an entity-specific implementation timeline to be included in the process developed in R1, with R2 stating that an entity shall implement its R1 process in accordance with its timeline in R2.

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer: No

Answer Comment:

See our response to Question 2 above.

The implementation plan indicates there is 12 months to become compliant. This could create confusion since many aspects of the standard are based on a 6 year interval. Consider if the implementation plan should match the maximum interval or clearly address what must be completed to be compliant as part of the implementation plan.

Can the drafting team clarify if all protection systems on an entities' system must have a coordination evaluation meeting the new process for PRC-027 within the first six years? The standard also gives the impression that the baseline fault current percentage option does not require all protection systems to be evaluated for coordination until the fault current threshold is met.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

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

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer: No

Answer Comment:

24 months would be more appropriate given the amount of work necessary to meet compliance.

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer: No

Answer Comment:

It is not clear how long an Entity has to develop a baseline, 12 months or 6 years. We would appreciate clarification on this in the implementation plan.

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

CSU agrees with SMUD's Comments concerning a potentially more effective approach to PRC-027. In addition to supporting their comments CSU also would make the following comment if the standard were to remain similar to its current construction.

Is it the intention that an entity would have an initial/baseline review of all protections system settings completed prior to the effective date of this standard? If this is the intent then the implementation period needs to be extended or a phased approach adopted as is done with PRC-005-2 for example.

Document Name:

Likes: 0

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 3, Poston James
Santee Cooper, 5, Pierce Lewis

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 6, Brown Michael
Santee Cooper, 3, Poston James

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer: No

Answer Comment:

Hydro One Networks Inc. agrees with NPCC on the following:

The Implementation Plan should be extended to 24 months or greater. As it stands now, entities are only given 12 months to develop a process, establish a Fault Current baseline, and establish a tracking tool for Fault Current baseline changes and/or periodic review. This period is far too short, and should be extended.

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

John Bee - Exelon - 3 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Vince Catania - Exelon - 5 -	
Selected Answer:	
Answer Comment:	
Document Name:	
Likes:	0
Dislikes:	0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

1. The implementation plan should explicitly indicate that entities are not expected to be 100% compliant with R2 on the effective date of the standard. Further, the implementation plan should state that the applicable entities are to begin implementing the process it established in response to R1 on the effective date of the standard.

2. There is an issue with the establishment of the baseline noted in our answer to question #4 which potentially could be addressed in the Implementation Plan.

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The Implementation Plan needs to address the 6 year review in Part 1.3. Is this 15 percent per year for the first 6 years? Do entities need to demonstrate when the last review was done prior to effective date of the Standard?

The Implementation Plan should be extended to 24 months. As it stands now, the 12 months entities have to develop a process, establish Fault current baseline, and establish a tracking tool for Fault current baseline changes and/or periodic review is not enough time.

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

We agree with the proposed Implementation Plan as it was explained by the SDT during the the 4/27/2015 project webinar. However, we believe a modified format would add clarity around the PRC-027-1 compliance dates. As written, it could be interpreted that every applicable Protection System setting that already exists needs to be reviewed using the process established in accordance with Requirement R1 by the “first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required to go into effect.” We believe that completing a review of all existing applicable settings concurrently with the effective date of R1 is unrealistic, and is not what the drafting team intended. We request the SDT consider modifying the Implementation Plan format as suggested below to help add clarity around the R2 compliance date for pre-existing PRC-027 applicable settings.

Requirement R1

"...first day of the first calendar quarter that is twelve (12) months after the date that the standard is approved by an applicable governmental authority…"

(Rationale – consistent with the posted Implementation Plan)

Requirement R2 (for new Protection Systems to be placed in service after the effective date of R1, or for existing Protection System settings affected by Bulk Electric System changes occurring after the effective date of R1) :

"...first day of the first calendar quarter that is eighteen (18) months after the date that the standard is approved by an applicable governmental authority…"

(Rationale – this would give entities ~6 months to start implementing the R1 process for new settings and begin to build an evidence trail for R2)

Requirement R2 (for existing Protection System settings that were developed and implemented prior to the R1 effective date):

"...first day of the first calendar quarter that is eighty-four (84) months after the date that the standard is approved by an applicable governmental authority…"

(Rationale – this would more clearly communicate the six year interval intended by the drafting team, following development of the R1 process, to fully implement the initial six year review interval required by R1/1.3. Some legacy settings may be reviewed earlier if BES changes warrant.)

Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer: No

Answer Comment:

Reclamation suggests that a two-year implementation period is more appropriate for updating both internal and external procedures regarding relay coordination. Particularly with regard to R1.5 external coordination procedures, registered entities may need to coordinate procedures with a number of other registered entities.

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

The implementation plan is not clear when the first performance of the tasks required in the Protection System coordination process document is required. For example, when must the first review of Protection System settings per Part 1.2 or 1.3 be conducted? On the effective date of the standard? Based on a date established in the process document?

We ask the drafting team to combine PRC-001 with PRC-027 to avoid confusion and cross referencing of two standards on the same topic. This should be handled in the development phase, which would require a modification to the implementation plan.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer: No

Answer Comment:

AECI believes that for some systems, especially those with a large amount of interconnections, there may be additional time past 1 year to properly establish **accurate** baselines and coordinate a process docuent with neighbors. An additional year for development of the plan and baselines is requested. Six year review periods seems reasonable and adequate.

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer: Yes

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

4. 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 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dan Roethemeyer - Dynegy Inc. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lynda Kupfer - Puget Sound Energy, Inc. - 5 -

Selected Answer:

Answer Comment:

CIP-014-2 is positioned to become effective the day after CIP-014-1 becomes effective, with -1 being retired at midnight of the same day it becomes effective. This might not be an issue of -1 is superseded by -2, and never becomes effective, but you never know.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Nick Vtyurin - Manitoba Hydro - 1,3,5,6 - MRO

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Malloy - Idaho Falls Power - 3 - WECC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Donna Stephenson - Great River Energy - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeff Wells - Grand River Dam Authority - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Brian Bartos - CPS Energy - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

(1) 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”?

(2) In R1 Part 1.3, “current baseline” is not defined. Current baseline is defined in the Supplemental Material Section, but because the Supplemental Material Section is merely guidance, can an entity make up its own definition of “current baseline”?

(3) In R1 Part 1.3, the Requirements nor the implementation plan define when a “time interval” begins. This should be in the Requirements or implementation plan, because the supplemental material section is unenforceable.

(4) In R1 Part 1.3, 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?

(5) 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”?

(6) 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?

(7) 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%?

(8) In Requirement R1, 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.

Document Name:

Likes: 0

Dislikes: 0

John Fontenot - Bryan Texas Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

As indicated in a number of our previous comments, we continue to disagree with the treatment to Requirement R1 in the proposed PRC-001-3.

Requirement R1, as written, is not measurable and should be rescinded or mapped into another standard. While revising PRC-001-3 to reflect the mapping of certain requirements (e.g. R3) to PRC-027 is necessary, not

revising other requirements that are unclear or unnecessary in the same standard that being revised fails to take advantage of the opportunity of an initiated project. Quite simply, familiarity with and knowledge of the purpose and limitations of Protection System schemes applied in an operating entity’s area are inherent to the entities that are required to comply with the rest of PRC-001-2. R1, therefore, is redundant and unnecessary. In addition, this requirement is not measurable. An analogy to this argument is that an RC needs to monitor its system conditions against IROLs. Since the RC is already required to prevent exceedances of IROLs and to apply mitigating measures to reduce flows to below IROLs within Tv, having monitoring capability is inherent to achieving these objectives. Hence in IRO-009-1, there are no requirements that stipulate the need to monitor flows/conditions against IROLs.

The above view is consistent with the Independent Experts Review Panel’s recommendation. If the SDT continues to opine that the retirement of PRC-001-2 Requirement R1 falls outside the scope of this project, then we would suggest the SDT to immediately submit an addendum or revised SAR to the Standards Committee for approval to post for industry comment, then revise/remove R1 accordingly.

We offered a similar comment about a year ago when the proposal was to keep only R1 in PRC-001 until this requirement is incorporated into a PER standard. No actions have been taken since. Had an addendum SAR or a revised SAR been posted then, the PRC-001-2 R1 issue would have been fully addressed by now. We are disappointed that over this period, neither NERC staff nor the PRC-027 SDT took the proactive action to proactively address/close out the issue. Today, we still have a requirement that is improper and not measurable. Once again, we urge NERC staff and the SDT to act now to post an addendum SAR or a revised SAR to fully resolve this issue. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.

Document Name:

Likes: 0

Dislikes: 0

Barbara Kedrowski - We Energies - Wisconsin Electric Power Co. - 3,4,5 - RFC

Selected Answer:

Answer Comment:

We would like this standard to state which relay elements that NERC wants to see coordinated. This could be in an attachment similar to PRC-019-1 and 025-1. Specifically for generator protection, there are so many different protection elements used that it would make the standard easier to use for the end user and an auditor if they had a specific set of relay elements to look for.

Finally, 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.

Document Name:

Likes: 0

Dislikes: 0

Si Truc Phan - Hydro-Qu?bec TransEnergie - 1 - NPCC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Mike Smith - Manitoba Hydro - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Shaw - Lower Colorado River Authority - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

It makes sense that, out of the five components of the NERC-defined Protection System, the owner of the Protective relays which respond to electrical quantities would be the one required to meet PRC-027. To address situations where multiple TOs or GOs may own different portions of the Protection System, LCRA TSC recommends changing to the language in the Applicability section to read as shown below:

4.1.1 Transmission Owner (that owns the Protective relays which respond to electrical quantities portion of the Protection System)

4.1.2 Generator Owner (that owns the Protective relays which respond to electrical quantities portion of the Protection System)

Document Name:

Likes: 0

Dislikes: 0

Michael Moltane - International Transmission Company Holdings Corporation - 1 -

Selected Answer:

Answer Comment:

Comments: R1.3 needs clarity around establishing the initial fault current baseline. Does this occur prior to Effective Date? Any time prior to first 6 year fault current review?

R1.5.3 needs clarity which party is responsible to verify issues are addressed prior to implementation. We assume the SDT intends this responsibility to be only on the party proposing the settings.

Document Name:

Likes: 0

Dislikes: 0

Jim Nail - City of Independence, Power and Light Department - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Alshare Hughes - Luminant - Luminant Generation Company LLC - 4,5,6 - TRE

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Robert Hirchak - Cleco Corporation - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Rick Terrill - Luminant - Luminant Generation Company LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Patricia Robertson - BC Hydro and Power Authority - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Thomas Foltz - AEP - 5 -

Selected Answer:

Answer Comment:

The applicability of PRC-027 should be limited to Protection Systems installed on interconnecting elements. There is no justification to include all BES Protection Systems in the standard. The requirements in PRC-001-2, R2 and R3, which PRC-027 is replacing, are limited to the coordination of protection systems between different entities. The SAR posted for PRC-001-1 System Protection Coordination (Project 2007-06) does not include expanding the scope of the standard to include all BES protection systems. If FERC seeks a protection system coordination standard that includes all BES protection systems, then the NERC standard development process should be followed by creating a new SAR.

Document Name:

Likes: 0

Dislikes: 0

Joseph Bencomo - PPL NERC Registered Affiliates - 1,3,5,6 - MRO,WECC,NPCC,SERC,SPP,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brytowski - Michael Brytowski On Behalf of: Donna Stephenson, Great River Energy, 5, 3, 1, 6

Selected Answer:

Answer Comment:

GRE supports the comments of the MRO NSRF and ACES

Document Name:

Likes: 0

Dislikes: 0

Michelle D'Antuono - Oxy - Ingleside Cogeneration LP - 5 -

Selected Answer:

Answer Comment:

It took four iterations of PRC-027-1 to come up with requirements acceptable to stakeholders that captured each relay owner's responsibility during the course of a coordinated assessment. This included the types of system changes that would trigger a coordinated study, the information to be shared, the timeframes to respond, and the expected actions to take at each point of the process. Although FERC staff did not call for the removal of those requirements, the project team has chosen to do so. These requirements should be reinstated. Without them, it is possible than an unresponsive neighbor cannot be compelled to participate in a coordinated relay assessment – leaving entities exposed to a NERC violation.

Document Name:

Likes: 1 Oxy - Occidental Chemical, 7, Greaff Venona

Dislikes: 0

Sergio Banuelos - Tri-State G and T Association, Inc. - 1,3,5 - MRO,WECC

Selected Answer:

Answer Comment:

While we agree that Part 1.3 is an essential element of a successful coordination process, we have concerns about how the baseline bus fault currents are determined in the "Supplemental Material" Section addressing Part 1.3. The last paragraph on page 13 of the standard states that "The baseline can be Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect." That implies that an entity must search its archives to determine whether it has available documentation of Fault currents that were used for initial settings. Then, only if no documentation can be found, the entity can choose to use its most recent short-circuit study data for the baseline. Tri-State believes that, if the second option is acceptable for cases when no documentation is available, it ought to be acceptable to use the most recent short-circuit study at the time the standard becomes effective for all of its bus Fault currents. Our recommendation is to remove "where not available" and the associated commas from the referenced paragraph on page 13.

Document Name:

Likes: 1 Tacoma Public Utilities (Tacoma, WA), 1, Merrell John

Dislikes: 0

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

Selected Answer:

Answer Comment:

Tacoma Power thanks the drafting team for their efforts and appreciates the opportunity to comment and help to guide the development of this standard.

Together with several other entities, Tacoma Power questions the need to mandate intra-entity coordination as part of an enforceable standard. Despite its reservations about the scope of the proposed standard, Tacoma Power assumes that, because FERC staff expressed concern that intra-entity coordination be included, there is little that the industry can do to limit the scope of PRC-027-1 to inter-entity coordination (i.e., Part 1.5 of Requirement R1). Tacoma Power's comments are based upon this assumption.

On page 14 of the Supplemental Material section, Tacoma Power recommends changing 'necessitates' to 'allows.' An entity may elect to review settings prematurely and reset the baseline for that/those bus(es), even though changing the baseline is not necessary.

The draft standard does not seem to address what latitude applicable entities will have when defining their tolerance for coordination. For example, under how many System contingencies does coordination need to be maintained? Must coordination be maintained for all single Protection System component failures? On the other hand, provided that planning and operations personnel/entities are aware, could applicable entities intentionally mis-coordinate Protection Systems? Tacoma Power's understanding is that the drafting team primarily has the following intents. (1) An applicable entity should be aware of how their Protection Systems will likely perform during Fault conditions under identified contingencies. (2) An applicable entity should be aware of contingencies under which Protection System performance during Faults may be unknown or adverse. (3) Operations and planning personnel/entities should be aware of contingencies under which Protection System performance during Faults may be unknown or adverse. To this end, Tacoma Power recommends that the Purpose be "To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those Faults, such that the Protection Systems operate in the intended sequence during Faults." Similarly, Tacoma Power recommends Facilities be "Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating those

Faults." This revised verbiage replaces "those faulted Elements" with "those Faults" to allow for removal of Elements other than the faulted Element(s), provided that the sequence is intended.

The Purpose statement includes the phrase "such that the Protection Systems operate in the intended sequence during Faults." This could be interpreted in a couple ways. The first interpretation is that the primary Protection System is supposed to operate first and not the backup Protection System. The second interpretation is that, not only does the primary Protection System need to operate first, but that the backup Protection System must be capable of operating for (detect) all Faults within the primary Protection System's zone of protection. Could the drafting team please identify the more correct interpretation of the Purpose? The burden of proof could be substantially different between the two interpretations.

If PRC-027-1 is approved, Tacoma Power's understanding is that a Mis-operation due to mis-coordination will not automatically imply that a violation of PRC-027-1 occurred.

Remove the extra 'The' just before Compliance Monitoring and Enforcement Program.

Tacoma Power believes that the drafting team should leverage the Lower and Moderate VSLs. The Lower VSL for both Requirements R1 and R2 should be for failing to include one Part. The Moderate VSL should be for failing to include two Parts, the High VSL should be for failing to include three Parts, and the Severe VSL should be for failing to include four (or more) Parts OR for failing to establish/implement the process. 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 and Moderate VSLs, even though PRC-001-1 did not. If the drafting team disagrees, then Part 1.5 of Requirement R1 should be separated into a separate requirement so that the other Parts of Requirement R1 can have more graduated VSLs since these other Parts do not map as well to PRC-001-1.

Compared to Requirement R1, Tacoma Power is not convinced that the justification has been made for a High VRF for Requirement R2.

Tacoma Power's understanding is that, where the NERC-defined term 'Fault' is used, the standard primarily, if not exclusively, means short circuits, as opposed to broken wires or intermittent connections.

Although entities are supposed to develop their own processes, the draft standard is specific enough that a flow chart may be helpful to visualize the process.

In the Supplemental Material section, it would be very helpful to include a series of examples of how Part 1.2 might be triggered and how an applicable entity might approach the review of Protection System settings. Examples might include a new substation, a new transmission Element, a new generator, a change in the impedance of an Element, and/or Protection System setting changes without any System change (e.g., setting philosophy change, relay replacements). In the examples, it would be helpful if the drafting team could discuss how to determine how far back into the existing System to look in response to the triggers.

Document Name:

Likes: 0

Dislikes: 0

Steven Rueckert - Western Electricity Coordinating Council - 10 -

Selected Answer:

Answer Comment:

In the Applicability Section of PRC-027-1, the DP applicability is limited to those DPs that "own Protection Systems identified in the Facilities section 4.2." However, throughout the standard when the DP is identified as the applicable entity, the qualifier is not included. Does the SPCSDT believe that it is clear in the requirements and rationale boxes that the DP applicability is only to those DPS that own Protection Systems identified in the Facilities section 4.2? If one were to read the requirements without fully understanding the applicability section, it appears that they are applicable to all DPs. Would it be better for clarity to include the "own Protection Systems identified in the Facilities section 4.2" language with all references to the DP?

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

While we like the opennes of the standard, we would like more defined measures to document compliance. Additionally, we would like a reference document that addresses the administrative requirements that the program would have to address.

Document Name:

Likes: 0

Dislikes: 0

Venona Greaff - Oxy - Occidental Chemical - 7 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Haase - Seattle City Light - 1,3,4,5,6 - WECC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Anthony Jablonski - ReliabilityFirst - 10 -

Selected Answer:

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 believes that the term "coordination" as it is used in Requirement 1, Parts 1.5.2 and 1.5.3 is ambiguous and notes that it is not defined within PRC-027-1 or the NERC Glossary Terms. Adding to this ambiguity, the term is used within a number of other Standards, and could be interpreted to refer to 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 1.5.2 and 1.5.3 to incorporate this new definition of “Protection System Coordination” (highlighted in red below):**

1.5.2. Review proposed Protection System settings provided by other functional entities, and respond regarding the proposed settings. The response should identify any Protection System Coordination issue(s) or affirm that no Protection System Coordination issue(s) were identified.

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

Document Name:

Likes: 0

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

The NSRF has noticed that the SDT has written the following note in PRC-001-3 Redline with mapping: *The Independent Experts concluded that PRC -00 Requirement R1 contains ambiguous language and suggested that it be incorporated into the PER standards. The Independent Experts further suggested that all of the training requirements in NERC’s Reliability Standards be consolidated*.

The NSRF questions why the SDT has not addressed this issue?

Document Name:

Likes: 0

Dislikes: 0

Kelly Dash - Con Ed - Consolidated Edison Co. of New York - 1,3,5,6 - NPCC

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Selected Answer:

Answer Comment:

We wish to express support for the direction the Standard Drafting Team has taken in this major re-write to formulate Draft 5 of the Standard. Some clarifications and extension of the Implementation Plan, as noted in the comments, are all that should suffice to arrive at a future successful draft Standard.

Document Name:

Likes: 0

Dislikes: 0

Mark Holman - PJM Interconnection, L.L.C. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Kathleen Black - DTE Energy - 3,4,5 - RFC

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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 thanks the drafting team for the opportunity to comment. SMUD would prefer more of a carrot and stick approach. SMUD views the current draft as burdensome due to the amount of documentation that will be needed to prove steps 1.1-1.4 were performed on every single BES Protection System. A better approach would be to establish a trigger or threshold that says you must follow these rules if you have "too many" coordination Misoperations. This trigger or threshold provides entities an incentive to coordinate relay settings thus avoids the compliance burden. This would be in alignment with the goal of reducing Misoperations rather than documenting procedural compliance. We think this would better represent RBS and at least we could support such an approach.

Document Name:

Likes: 1 Braden Nick On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4, James McFall, Modest

Dislikes: 0

Nick Braden - Nick Braden On Behalf of: Jack Savage, Modesto Irrigation District, 3, 6, 4
James McFall, Modesto Irrigation District, 3, 6, 4

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Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Andrew Pusztai - American Transmission Company, LLC - 1 -

Selected Answer:

Answer Comment:

While ATC supports the direction the SDT is going on this draft Standard, there are still some concerns that result in ATC maintaining a “negative” ballot position.

On page 13 of 16 of Draft 5, ATC recommends removing the phrase, “where not available” from the last paragraph. An entity should be able to use the fault current values from the most recent short-circuit study for a baseline. Fault current values from the initial settings, while available, could be contained in many different formats from prior years and not readily available in a database.

In re-working Draft 5 of PRC-027-1, ATC recognizes and appreciates the drafting team’s efforts to allow an entity flexibility in developing its coordination process. However, ATC also believes that the focus of PRC-027-1 should be on improving BES reliability and the current draft does not necessarily achieve that end. The definition of a review could be left up to interpretation, which could lead some companies to perform the function to meet the requirement with no benefit realized. 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. There is no clear connection in the

PRC-027-1 requirements to system performance using PRC-004 Misoperations data, and as echoed in our comments to Question 1, there is no feedback loop for monitoring improvement.

Document Name:

Likes: 0

Dislikes: 0

John Seelke - Public Service Enterprise Group - 1,3,5,6 - NPCC,RFC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

a. Clarify the scope of PRC-027-1: We understand from the Webinar on 4/27/15 that the standard is intended to address Protection System setting for Faults associated with Normal Clearing (i.e., the Protection Systems operate properly per the definition of “Normal Clearing”) and normal operation of the interrupting devices (i.e., they also operate correctly). In other words, the setting of back-up Protection Systems that would operate due to the failure of a Protection System or circuit breaker to operate correctly is outside the scope of the standard. The standard should clearly state this in the Applicability section.

b. Provide default information by separate attachments to the standard: To avoid additional work by each registered entity in developing its process under R1 process, the standard should have certain “default” information provided in separate attachments as discussed below. Furthermore, an entity should be able to either adopt the attachment or modify it, provided that its modifications are explained in its process.

· - Part 1.1: This subpart is presently “A method to review and update the information required to develop new or revised Protection System settings.” We believe that “the information required to develop new or revised Protection System settings” is not entity-specific, but Protection System-specific. That information should be included in the standard via an attachment.

· - Part 1.3: This subpart should also reference an attachment to the standard that designates the Protection System types that need to be included in the periodic review. For example, It would not make sense for one entity to include some Protection System, and another entity to exclude the same protection system due to a different interpretation of the standard. There are only a finite number of protection system types, and they should be listed as "included" or "excluded" as part of the standard. That information should be included in the standard via an attachment.

c. Clarify the first bullet in Part 1.3 "Periodic Fault current studies" on two points:

· The phrase "an established Fault current baseline" is unclear with respect to timing. It would be clearer if the team replaced the aforementioned phrase with the following one: "a Fault current study that is no older than six calendar years." Then a 2020 review for a bus under this bullet must use Fault current that was calculated in 2014 or later.

We recommend modifying the phrase ", and evaluated in a time interval not to exceed six calendar years" in the first bullet in Part 1.3 to ", with such Fault current changes evaluated in a time interval not to exceed six calendar years. "

Document Name:

Likes: 0

Dislikes: 0

Russ Schneider - Flathead Electric Cooperative - 4 -

Selected Answer:

Answer Comment:

I am compelled by other commentors that pointed out in previous drafts that the shift from inter-connected elements to intra-connected elements is potentially a broad expansion of scope for little reliability benefit. The industry just spent several years getting more definition on the scope and most other protection system issues are covered in other standards as noted in the Protection System Issues Addressed by Other Projects.

More specifically, if the intra-coordination regulatory burden does have reliability benefit it should be limited to BES Transmission Owners in the applicability section. 4.1.2, 4.1.3, and 4.2 should be eliminated.

Document Name:

Likes: 0

Dislikes: 0

Joseph Smith - PSEG - Public Service Electric and Gas Co. - 1 -

Selected Answer:

Answer Comment:

a. Clarify the scope of PRC-027-1: We understand from the Webinar on 4/27/15 that the standard is intended to address Protection System setting for Faults associated with Normal Clearing (i.e., the Protection Systems operate properly per the definition of "Normal Clearing") and normal operation of the interrupting devices (i.e., they also operate correctly). In other words, the setting of back-up Protection Systems that would operate due to the failure of a Protection System or circuit breaker to operate correctly is outside the scope of the standard. The standard should clearly state this in the Applicability section.

b. Provide default information by separate attachments to the standard: To avoid additional work by each registered entity in developing its process under R1 process, the standard should have certain "default" information provided in separate attachments as discussed below. Furthermore, an entity should be able to either adopt the attachment or modify it, provided that its modifications are explained in its process.

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c.   Clarify the first bullet in Part 1.3 “Periodic Fault current studies” on two points:

·   The phrase “an established Fault current baseline” is unclear with respect to timing. It would be clearer if the team replaced the aforementioned phrase with the following one: “a Fault current study that is no older than six calendar years.” Then a 2020 review for a bus under this bullet must use Fault current that was calculated in 2014 or later.

We recommend modifying the phrase “, and evaluated in a time interval not to exceed six calendar years” in the first bullet in Part 1.3 to “, with such Fault current changes evaluated in a time interval not to exceed six calendar years. “

Document Name:

Likes: 0

Dislikes: 0

Jamison Cawley - Nebraska Public Power District - 1 -

Selected Answer:

Answer Comment:

In the past for draft 4 of PRC-027 it was stated in part 1.1.1 of the application guidelines that, “Faults on the BES, but records collected for Reliability Standard PRC-004 do not indicate that lack of coordination was the predominate root cause of reported Misoperations.” Considering this, why are additional standard requirements being implemented if data does not support it?

How was the 15% change in fault current determined? Perhaps this percentage should be eliminated and allow each entity to specify this type of fault current percentage threshold as part of their own process.

R1.3. states there should be a review of protection system “settings”. Should this state protection system “coordination-related settings”? This standard is not addressing all aspects of how to set a relay but is addressing coordination, which involves timers and time current curves rather than say a distance impedance reach magnitude. Consider if “settings” should be changed to “coordination related settings” in the standard.

A 6 year time horizon option to review settings seems a bit arbitrary. A longer time horizon may be better suited for very large systems. Consider allowing this time interval to be defined as part of the process for each utility so they can be flexible since the number of systems to coordinate will vary greatly between utilities.

For R1.1. why does PRC-027 contain all the detailed model and equipment verifications for an auditor while other standards like PRC-006, 010, 019, 023, 024 and 025 do not? The need for accurate model and equipment data is correct; however, the efforts to supply proof of this information to an auditor appears to be excessive in terms of auditing proof compared to other standards. The result of this requirement as it will be implemented in R2. is that the auditor will essentially be reviewing the relay settings and accuracy of the model and equipment records. This does not seem practical. We would recommend removal of this requirement.

In the purpose statement, could Protection Systems be changed to Protective Relays? Protective relays are installed for the purpose of detecting faults on BES elements and isolating those faulted elements. We do not feel that associated communications systems, voltage and current sensing devices, station batteries, or DC control circuitry are installed for those purposes.

In the Rationale for Requirement R1., we don’t consider all the listed examples of information to be essential for coordination, especially the functional drawings, which are very high level, and station configuration, which would be single bus/ring bus/etc. Why are these essential?

In the Rationale for Requirement R1, Part 1.2., there are absolute terms regarding system changes, such as “that alters ANY”, and “result in A change”. We suggest a change to some wording that would allow some minor changes that wouldn’t require a coordination review.

Regarding Requirement R1, we would need to review and verify all line, generator, and transformer impedances to verify our short circuit study is accurate. The supplemental material calls for a review of interconnected TO, GO, and DP information to determine whether their systems are correctly modeled in the short circuit study. This is a concern in that we would have to determine other utilities' models.

Document Name:

Likes: 0

Dislikes: 0

Don Schmit - Nebraska Public Power District - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Tony Eddleman - Nebraska Public Power District - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Terry BIlke - Midcontinent ISO, Inc. - 2 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

As indicated in a number of our previous comments, we continue to disagree with the treatment with respect to Requirement R1 in the proposed PRC-001-3.

Requirement R1, as written, is not measurable and should be rescinded or mapped into another standard (e.g. a PER standard) and revised to become a training requirement. While revising PRC-001-3 to reflect the mapping of certain requirements (e.g. R3) to PRC-027 is necessary, not revising other requirements that are unclear or unnecessary in the same standard that is being revised fails to take advantage of the opportunity of an initiated project. Quite simply, familiarity with and knowledge of the purpose and limitations of Protection System schemes applied in an operating entity's area are inherent to the entities that are required to comply with the rest of PRC-001-2. R1, therefore, is redundant and unnecessary. An analogy to this argument is that an RC needs to monitor its system conditions against IROLs. Since the RC is already required to prevent exceedances of IROLs and to apply mitigating measures to reduce flows to below IROLs within Tv, having monitoring capability is inherent to achieving these objectives. Hence in IRO-009-1, there are no requirements that stipulate the need to monitor flows/conditions against IROLs.

The above view is consistent with the Independent Experts Review Panel's recommendation. If the SDT continues to opine that the retirement of PRC - 001 -2 Req would suggest the SDT to immediately submit an addendum or revised SAR

to the Standards Committee for approval to post for industry comment, then revise/remove R1 accordingly.

We offered a similar comment about a year ago when the proposal was to keep only R1 in PRC-001 until this requirement is incorporated into a PER standard. No actions have been taken since. Had an addendum SAR or a revised SAR been posted then, the PRC-001-2 R1 issue would have been fully addressed by now. We are disappointed that over this period, neither NERC staff nor the PRC-027 SDT took the proactive action to proactively address orclose out the issue. Today, we still have a requirement that is improper and not measurable. Once again, we urge NERC staff and the SDT to act now to post an addendum SAR or a revised SAR to fully resolve this issue. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.

Document Name:

Likes: 0

Dislikes: 0

Mike ONeil - NextEra Energy - Florida Power and Light Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Oliver Burke - Entergy - Entergy Services, Inc. - 1 -

Selected Answer:

Answer Comment:

Entergy is not in agreement with the selection of High Violation Severity Level (VSL) for Requirement 1.5.3. A more appropriate VSL would be Lower VSL.

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Karl Blaszkowski - CMS Energy - Consumers Energy Company - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Molly Devine - IDACORP - Idaho Power Company - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Richard Hoag - Richard Hoag On Behalf of: Cindy Stewart, FirstEnergy - FirstEnergy Corporation, 1, 3

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

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.

Document Name:

Likes: 0

Dislikes: 0

Greg Davis - Greg Davis On Behalf of: Jason Snodgrass, Georgia Transmission Corporation, 1

Selected Answer:

Answer Comment:

GTC is in support of the SERC Comments:

1) Please revise the Purpose because it implies the Protection System isolates the fault. The NERC defined Protection System includes the trip coil but stops there. Our suggested wording replaces 'isolating' with 'initiating isolation of', which results in 'To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.'

2) Please revise the Facilities consistent with the revised Purpose in item 1 above. Our suggested wording replaces 'isolating' with 'initiating isolation of', which results in 'Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements.'

3) Supplemental Material p13 at bullet (Option 1) states '…from an established Fault current baseline for Protection Systems at the bus under study, …' Please clarify that the 'bus under study' is typically the BES bus at or above 100kV. We suggest adding 'For a TO the busses under study are typically their list of BES busses at or above 100kV. For a GO or DP, the busses under study are typically the list of BES busses at or above 100kV which they connect to; such busses may well be owned by the TO.' This should also help allay some concerns about intended scope.

4) Supplemental Material p13 bottom and top of p14 states 'The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect.' Please delete 'where not available' as this is burdensome and inconsistent with the intended scope.

5) Supplemental Material p13: Please add another example to help GO understand what most likely needs to be coordinated across the GO-TO interface. We suggest adding it between '…its zone of protection.' and 'Based on stakeholder comments …' and starting a new paragraph with your existing 'Based on stakeholder comments …' sentence. We suggest adding: 'Also for example a GO would typically include the generator step-up transformer neutral time overcurrent on its H0 bushing because its fault current could change due to generator, transformer, or BES changes or a combination of them.'

Document Name:

Likes: 0

Dislikes: 0

David Thorne - PHI - Potomac Electric Power Co. - 1 -

Selected Answer:

Answer Comment:

The standard addresses the establishment of a process to develop/review settings and to implement the process. It does not address implementing the "settings" that result from the process. Should there be a requirement concerning implementation of revised settings?

Document Name:

Likes: 0

Dislikes: 0

Kaleb Brimhall - Colorado Springs Utilities - 5 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

CSU agrees with SMUD's Comments concerning a potentially more effective approach to PRC-027., but in regards to PRC-001 CSU has some small modifications that CSU thinks will clarify the intent of some verbiage in PRC-001.

1. R2.1 and R2.2 – "Protection System component failure that adversely impacts the Reliable Operation of the BES" should replace the verbiage currently in the standards which currently states "protective relay or equipment failure reduces system reliability." This uses defined terms that clarifies what is meant by this statement.

2. PRC-001-3, R1 – If the verbiage is not clarified using defined terms then there needs to be some clarification concerning "reduces system reliability". CSU recommends the above verbiage using defined terms to clarify this ambiguity.

Document Name:

Likes: 1 Colorado Springs Utilities, 3, Morgan Charles

Dislikes: 0

Shawna Speer - Colorado Springs Utilities - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Charles Morgan - Colorado Springs Utilities - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

manon paquet - manon paquet On Behalf of: Roger Dufresne, Hydro-Qu?bec Production, 1, 5

Selected Answer:

Answer Comment:

This draft of the standard is less limited than previous versions. It allows responsibles entities to establish a global process that meets their needs.

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Connie Lowe - Dominion - Dominion Resources, Inc. - 3 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

1) Please revise the Purpose because it implies the Protection System isolates the fault. The NERC defined Protection System includes the trip coil but stops there. Our suggested wording replaces ‘isolating’ with ‘initiating isolation of’, which results in ‘To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.’

2) Please revise the Facilities consistent with the revised Purpose in item 1 above. Our suggested wording replaces ‘isolating’ with ‘initiating isolation of’, which results in ‘Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements.’

3) Supplemental Material p13 at bullet (Option 1) states ‘…from an established Fault current baseline for Protection Systems at the bus under study, …’ Please clarify that the ‘bus under study’ is typically the BES bus at or above 100kV. We suggest adding ‘For a TO the busses under study are typically their list of BES busses at or above 100kV. For a GO or DP, the busses under study are typically the list of BES busses at or above 100kV which they connect to; such busses

may well be owned by the TO.' This should also help allay some concerns about intended scope.

4) Supplemental Material p13 bottom and top of p14 states 'The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect.' Please delete 'where not available' as this is burdensome and inconsistent with the intended scope.

5) Supplemental Material p13: Please add another example to help GO understand what most likely needs to be coordinated across the GO-TO interface. We suggest adding it between '…its zone of protection.' and 'Based on stakeholder comments …' and starting a new paragraph with your existing 'Based on stakeholder comments …' sentence. We suggest adding: 'Also for example a GO would typically include the generator step-up transformer neutral time overcurrent on its H0 bushing because its fault current could change due to generator, transformer, or BES changes or a combination of them.'

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

Jeni Renew - SERC Reliability Corporation - 10 - SERC

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

1) Please revise the Purpose because it implies the Protection System isolates the fault. The NERC defined Protection System includes the trip coil but stops there. Our suggested wording replaces 'isolating' with 'initiating isolation of', which results in 'To maintain the coordination of Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements, such that the Protection Systems operate in the intended sequence during Faults.'

2) Please revise the Facilities consistent with the revised Purpose in item 1 above. Our suggested wording replaces 'isolating' with 'initiating isolation of', which results in 'Protection Systems installed for the purpose of detecting Faults on BES Elements and isolating initiating isolation of those faulted Elements.'

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stakeholder comments …' and starting a new paragraph with your existing 'Based on stakeholder comments …' sentence. We suggest adding: 'Also for example a GO would typically include the generator step-up transformer neutral time overcurrent on its H0 bushing because its fault current could change due to generator, transformer, or BES changes or a combination of them.'

The comments expressed herein represent a consensus of the views of the above-named members of the SERC PCS only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.

Document Name:

Likes: 4 Santee Cooper, 1, Abrams Shawn
Santee Cooper, 6, Brown Michael
Santee Cooper, 5, Pierce Lewis
Santee Cooper, 3, Poston James

Dislikes: 0

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

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

As indicated in a number of our previous comments, we continue to disagree with the treatment to Requirement R1 in the proposed PRC-001-3.

Requirement R1, as written, is not measurable and should be rescinded or mapped into another standard. While revising PRC-001-3 to reflect the mapping of certain requirements (e.g. R3) to PRC-027 is necessary, not revising other requirements that are unclear or unnecessary in the same standard that is being revised fails to take advantage of the opportunity of an initiated project. Quite simply, familiarity with and knowledge of the purpose and limitations of Protection System schemes applied in an operating entity's area are inherent to the entities that are required to comply with the rest of PRC-001-2. R1, therefore, is redundant and unnecessary. In addition, this requirement is not measurable. An analogy to this argument is that an RC needs to monitor its system conditions against IROLs. Since the RC is already required to prevent exceedances of IROLs

and to apply mitigating measures to reduce flows to below IROLs within Tv, having monitoring capability is inherent to achieving these objectives. Hence in IRO-009-1, there are no requirements that stipulate the need to monitor flows/conditions against IROLs.

The above view is consistent with the Independent Experts Review Panel's recommendation. If the SDT continues to opine that the retirement of PRC-001-2 R1 Requirement falls outside the scope of this project, then we would suggest the SDT to immediately submit an addendum or revised SAR to the Standards Committee for approval to post for industry comment, then revise/remove R1 accordingly.

We offered a similar comment about a year ago when the proposal was to keep only R1 in PRC-001 until this requirement is incorporated into a PER standard. No actions have been taken since. Had an addendum SAR or a revised SAR been posted then, the PRC-001-2 R1 issue would have been fully addressed by now. We are disappointed that over this period, neither NERC staff nor the PRC-027 SDT took the proactive action to proactively address/close out the issue. Today, we still have a requirement that is improper and not measurable. Once again, we urge NERC staff and the SDT to act now to post an addendum SAR or a revised SAR to fully resolve this issue. Further delay in addressing the issue until a new project is initiated may result in dragging the approval of PRC-027-1 for another several months to a year.(Note – The last paragraph of these SRC comments represent a consensus of the ISOs/RTOs with the exception of ERCOT.)

Document Name:

Likes: 0

Dislikes: 0

christina bigelow - Electric Reliability Council of Texas, Inc. - 2 -

Selected Answer:

Answer Comment:

ERCOT supports the comments regarding removal and/or revision of Requirement R1 in PRC-001-1.1.

Document Name:

Likes: 0

Dislikes: 0

Donald Hargrove - OGE Energy - Oklahoma Gas and Electric Co. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 1 OGE Energy - Oklahoma Gas and Electric Co., 5, Staples Leo

Dislikes: 0

Payam Farahbakhsh - Hydro One Networks, Inc. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Paul Malozewski - Hydro One Networks, Inc. - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Chris Scanlon - Exelon - 1 -

Selected Answer:

Answer Comment:

Supplemental Material section 1.3, page 13/16 first bulleted paragraph (Option 1). The first two sentences are unclear, the clause starting with “or, Fault” and ending with “over time” and the following sentence starting with “the accumulation” are confusing.

Requirement R1 uses the words “to operate in the intended sequence during Faults” which makes sense for TOs but is not as clear for a GO/GOP. The SDT should attempt to address what, if anything, this means to a GO. Do GOs have to define this for faults at various locations on the transmission lines, inside the plant etc.? In general, this draft of PRC-027-1 is not clear enough for a Generator Owner (GO). The requirements applicable to a GO need to be clearly defined.

During the webinar, presenters talked about other GO relays other than distance and overcurrent, being in the scope of this standard. If that is the case, these should be clearly included in this standard and requirements for coordination should be part of this standard.

During the webinar, the presenters referred to coordination requirements discussed in IEEE standards and NERC SPCS Technical Reference Document (TRDs). Based on the response to questions asked by Exelon on the Webinar, it appears the SDT expects a GOs to implement some recommendations from IEEE guides or NERC TRDs which do not have the force of law and are not included in the requirements. The question was posed during the Webinar Q&A, “if a GO does not have protective relays which are dependent on the magnitude of fault current, then do they [drafting team] agree this standard is not applicable to the GO”. The response was that there are coordination requirements in IEEE standards and NERC TRD which a GO has to address. We disagree with that explanation. IEEE Guides and NERC Technical Reference Document have good guidance but are not enforceable. The way the question was answered implies that this standard requires a GO, under the conditions as stated above, to comply with the requirements. This should not be left to Auditors interpretation. We request the drafting team clarify the requirements to address this issue.

Document Name:

Likes: 0

Dislikes: 0

John Bee - Exelon - 3 -

Selected Answer:

Answer Comment:

See Exelon TO comments as submitted by C Scanlon for exelon

Document Name:

Likes: 0

Dislikes: 0

Vince Catania - Exelon - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Dave Carlson - Exelon - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Gerry Adamski - Essential Power, LLC - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Laurie Williams - PNM Resources - Public Service Company of New Mexico - 1 -

Selected Answer:

Answer Comment:

This standard is a step in the right direction and appreciate the efforts of the drafting team. Consideration should be given to schemes not impacted by changes in fault current. Perhaps language could be added that requires review of the schemes associated with any activity that changes the impedance characteristics of a BES line or transformer. Otherwise, schemes that are indifferent to changes in fault current (i.e. step-distance and differential) should be excluded from the current requirements, and should be subject to review as noted above or the drafting team should provide a technical basis for a 6-year review cycle.

Document Name:

Likes: 0

Dislikes: 0

Terri Pyle - OGE Energy - Oklahoma Gas and Electric Co. - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

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Selected Answer:

Answer Comment:

1. R1.1: Recommend expanding on existing language in the Rational/ Technical Guidelines to emphasize that 'method to review and update' is not a detailed verification of the entire model on a regular basis but a localized review where work is being done going forward.

2. R1.4: Recommend expanding on existing language in the Rational/ Technical Guidelines to indicate that this may be a simple gut check or could be a full review based on the scope of the project and/or the experience of the person doing the work. In either case, the scope of the review is up to the entity.

3. The Rational box for R1.3 correctly indicates that ‘The Fault current-based option requires an entity to first establish a Fault current baseline for Protection Systems at the bus under study to be used as a control point for future Fault current studies”; however, there is no requirement to establish such in the requirements nor in the Implementation Plan. As such, it seems like an entity could establish such a baseline sometime in the future and then make the comparison in the 60th month. As such the standard should clearly require an entity that plans to use the methodology stated in first bullet of 1.3 must establish a baseline prior to the effective date of the Standard. This could be accomplished with a new requirement in R1.3 or possibly in the Implementation Plan.

4. In the VSL tables, the second part of the OR statements for R1 and R2 are not needed and should be deleted. The first part of the OR statement includes the words “two or more”. The phase ‘or more’ includes ‘all elements’ which equates to failing to establish a review process at all.

5. There appears to be some indention/ formatting issues within the Supplemental material for R.1.3 and R.1.4.

6. During the NERC Webinar is was noted that the Supplemental material section states “The baseline can be the Fault currents used for initial settings development, or where not available, the Fault current values from the most recent short-circuit study available at the time the standard goes into effect.” It was indicated that the language might lead an auditor to ask for evidence that an entity researched for this data. Perhaps simply remove the words ‘where available’?

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

None.

Document Name:

Likes: 0

Dislikes: 0

Lee Pedowicz - Northeast Power Coordinating Council - 10 - NPCC

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Selected Answer:

Answer Comment:

We wish to express support for the direction the Standard Drafting Team has taken in this major re-write to formulate Draft 5 of the standard. Some clarifications and extension of the Implementation Plan, as noted in the comments, are all that should suffice to arrive at a future successful draft standard.

The approach that the System Protection Coordination Standard Drafting Team (SPCSDT) has taken by establishing a separate standard for Coordination of Protection System Performance During Faults (PRC -027), while another standard for protection coordination (PRC-001-3 System Protection Coordination) already exists creates an unnecessary administrative burden. The attributes of coordinating fault protection should be contained in a standard on System Protection Coordination. The argument is being made that other protection systems (UFLS, UVLS) have their own standards, and therefore fault clearing should have its own standard. There is an opportunity to consolidate and be less administrative by having only one standard.

Document Name:

Likes: 1 Hydro-Qu?bec TransEnergie, 1, Phan Si Truc

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Carol Chinn - Florida Municipal Power Agency - 4 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Section 4.2 should more clearly address the applicable generator Facilities, and FMPA suggests that it mirror the latest version of PRC-005, specifically section 4.2.5.

R1 refers to “BES Protection Systems” which could be interpreted in various ways, including those that go beyond what is described in the applicability section. FMPA suggests replacing the phrase “BES Protection Systems” in R1 with “Protection Systems identified in section 4.2”.

FMPA also recommends a rephrasing of R1 to make it more grammatically correct…”establish a process to develop settings for its Protection Systems identified in section 4.2 so that they operate in the intended sequence during Faults.”

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

1) Please consider revising the A.3 Purpose statement, and the A.4.2 Facilities statement, because they imply the Protection System isolates the fault. The NERC definition of “Protection System” includes the trip coil, but stops there. We suggest replacing “isolating” with “initiating isolation of” in both statements.

2) Supplemental Material p13 at bullet (Option 1) states “…from an established Fault current baseline for Protection Systems at the bus under study, …” Please clarify that the “bus under study” is typically the BES bus at or above 100kV. We suggest adding “For a TO the busses under study are typically their list of BES busses at or above 100kV. For a GO or DP, the busses under study are typically the list of BES busses at or above 100kV which they connect to; such busses may well be owned by the TO.” This should also help allay some concerns about intended scope.

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Document Name:

Likes: 0

Dislikes: 0

Leo Staples - OGE Energy - Oklahoma Gas and Electric Co. - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Texas RE requests clarification of the VSLs to explain if a "Part" is referring to a requirement or subrequirement. If it is referring to a subrequirement, Texas RE suggests specifically stating the subrequirement.

Texas RE suggests a thorough grammatical and consistency review on PRC-027-1 and PRC-001-3. Texas RE noticed the following:

- "The the" in Section 1.2 is duplicated;

- The timeframes and terminology are not consistent with the Rules of Procedure, risk-based compliance process, or the Glossary of Terms; and
- The VSL/VRF Levels are inconsistent with other standards being reviewed. There are not any "Levels of Non-Compliance for Generator Operators" but there are requirements for Generator Operators to follow. Is this because there are no "Measures" for those requirements with GOP responsibility? If there is not an adjustment to the VRF/VSL format, "Levels of Non-Compliance for Transmission Operators" in PRC-001-3, section 3.4 referring to Level 4 does not make sense.

Document Name:

Likes: 0

Dislikes: 0

Shawn Abrams - Santee Cooper - 1 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Michael Brown - Santee Cooper - 6 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

David Jendras - Ameren - Ameren Services - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Lewis Pierce - Santee Cooper - 5 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

James Poston - Santee Cooper - 3 -

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

Jason Marshall - ACES Power Marketing - 6 - MRO,WECC,TRE,SERC,SPP,RFC

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Selected Answer:

Answer Comment:

Why is PRC-001-1.1 R5 (i.e. the new R3) not being deleted as part of this project? It focuses on Protection System coordination as well.

Why did the drafting team leave PRC-001 R1 in effect? The words “familiar with” have been interpreted to be a training requirement. This should be retired as PER-005-2 would capture this requirement in the systematic approach to training.

Document Name:

Likes: 0

Dislikes: 0

Phil Hart - Associated Electric Cooperative, Inc. - 1 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes: 0

Dislikes: 0

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

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Selected Answer:

Answer Comment:

We are curious as to why the SDT has developed a Standard that requires establishing a “process” rather than a “methodology” which is more consistent with other Standards such as FAC and TPL for example (SOL Methodology, Facility Rating Methodology, etc.) Typically in the Standards, processes are included within plans and methodologies. In this Standard there seems to be a shift to a method within a process. We are curious if there is a specific, intended difference in the use of the “process” term.

Also, we would suggest capitalizing the terms ‘transmission’ and ‘load’ in Requirement R3 and sub-part R3.1 in PRC-001-3 standard as they are both defined in the NERC Glossary of Terms. Also, we would ask the drafting to provide clarity on why there are only two Measurements while there four Requirements in the standard.

Document Name:

Likes: 0

Dislikes: 0

Shannon Fair - Colorado Springs Utilities - 6 -

Error: Subreport could not be shown.

Selected Answer:

Answer Comment:

Document Name:

Likes:	0
Dislikes:	0