Consideration of Comments

Project 2010-05.1 Protection System (Misoperations)

The Project 2010-05.1 Protection System Misoperation Standard Drafting Team ("drafting team") thanks all commenters who submitted comments on the proposed Reliability Standard PRC-004-3 – Protection System Misoperation Identification and Correction. This standard was posted for a 45-day formal and public comment period from January 17, 2014 through March 11, 2014. Stakeholders were asked to provide comment on the standard and associated documents through a special electronic comment form. There were 63 sets of comments, including comments from approximately 173 different people from approximately 99 companies representing 9 of the 10 industry segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Background Information

The fourth draft of PRC-004-3 – Protection System Misoperation Identification and Correction Reliability Standard was posted for a 45-day formal comment period from January 17 – March 11, 2014 with an additional ballot in the last ten days of the comment period according to the new Standards Process Manual, June 26, 2013. Stakeholders from approximately 99 companies representing nine of ten industry segments provided comment. The Protection System Misoperation Standard Drafting Team (PSMSDT or SDT) has responded to all commenters and developed a fifth draft of the standard based on stakeholder comment. Changes to the standard include, but are not limited to following areas.

Summary of Changes

The PSMSDT made two substantive revisions to the previous draft 4 following the additional 45-day formal comment period of the standard and additional ballot which received 62.63% stakeholder approval. The following narrative is a summary of the two substantive revisions and other minor revisions made to the proposed draft 5 of the standard.

Definitions

The definition of "Composite Protection System" was revised for clarity. The first substantive revision is the definition of "Misoperation" concerning the two categories of "Slow Trip – During Fault." The

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

revision removes the "a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability" and uses the more clear "…if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System." The last category of "Unnecessary Trip – Other Than Fault" was revised slightly to clarify that a Protection System operation caused by on-site personnel is not a Misoperation and the SDT made other corresponding revisions to insert word "Composite" before "Protection System" for consistency with the proposed definition of "Composite Protection System."

Purpose Statement

No revisions.

Facilities

An exclusion for Remedial Action Schemes (RAS) and Special Protection System (SPS) has been provided to increase clarity that these Protection Systems are not applicable to the standard.

Effective Dates

The extended implementation provision of 24 calendar months previously provided to entities in the Western Electric Coordinating Council (WECC) Region was eliminated. The provision was originally proposed due to a perceived conflict that is no longer valid. The effective date language was inserted into Section 6 of the standard for completeness.

Requirement R1

The SDT made a non-substantive revision to more clearly describe that the BES interrupting device operation that meets the three sub-parts (i.e., 1.1, 1.2, and 1.3) must all be true to have a Protection System operation that is reviewable for Misoperation.

Requirement R2

The requirement is the second substantive revision to address a gap in performance identified through continued review during the formal comment period. The previous draft did not have a provision for the responsible entity to initiate a reliability activity under the standard in the case of a Protection System failure to operate a BES interrupting device which is what initiates the activity to review for Misoperation.

The SDT determined that a failed Protection System would cause backup protection to operate other BES interrupting devices; therefore, it is practical to have the responsible entity that provided backup protection to notify the other entity of the potential failure. It is the notification that eliminates the gap and causes the other entity to review the Protection System for Misoperation under the next Requirement, R3.

Requirement R3

Minor word change.

Requirement R4
Minor clarity revision by adding “for a Misoperation” to more clearly reference the Misoperation identified in either Requirement R1 or R3.

Requirement R5
No change.

Requirement R6
No change.

Measures M1-M6
Each of the six Measures were updated to provide the entity that is required to demonstrate compliance, what is demonstrated, and the reference to the corresponding Requirement. Revisions were based on stakeholder comment and to be consistent with drafting team guidance for developing Measures.

Compliance
The SDT clarified for Requirement R5 that evidence retention relates to the “development” of the Corrective Action Plan (CAP), each evaluation, and each declaration.

VRFs and VSLs
The drafting team made a couple of minor typographical corrections identified by stakeholders.

Application Guidelines
The SDT made a significant number of additions and clarifications to address stakeholder comment. Most notably in the section discussing the definition of Composite Protection System.

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory, or other Government Entities

10 —Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
4.	Sylvain Clermont	Hydro-Québec TransÉnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Alan MacNaughton	New Brunswick Power	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Québec TransÉnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Abouba	Hydro One Networks Inc.	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2. Group	Dianne Gordon	Puget Sound Energy	X		X		X					

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Erika Doot	US Bureau of Reclamation	X				X					

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Janet Smith	Arizona Public Service Company	X		X		X	X				

No Additional Responses

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Joseph DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
7.	Joseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Bos	Muscatine Power & Water	MRO	1, 3, 5, 6
14.	Scott Nickels	Rochester Public Utilities	MRO	4
15.	Terry Harbor	MidAmerican Energy	MRO	1, 3, 5, 6
16.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
17.	Tony Eddleman	Nebraska Public Utilities District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Richard Hoag	FirstEnergy Corp	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FirstEnergy Corp.	RFC	1
2.	Cindy Stewart	FirstEnergy Delivery	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dresner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FirstEnergy Solutions	RFC	6
6.	Brians Orians	FirstEnergy Solutions	RFC	NA
7.	Richard Hoag	FirstEnergy Corp.	RFC	NA
8.	Marissa Mclean	FirstEnergy Delivery	RFC	NA

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Mike O'Neil	Florida Power & Light	X									

No Additional Responses

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliate	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	Louisville Gas and Electric Company and Kentucky Utilities Company	SERC	3
2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Mike Garton	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion Resources Services, Inc.	SERC	1, 3, 5, 6
2.	Randi Heise	Dominion Resources Services, Inc.	RFC	5, 6
3.	Connie Lowe	Dominion Resources Services, Inc.	NPCC	5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	Michael Crowley	Virginia Electric and Power Company	SERC	1, 3
5.	Tom Owens	Virginia Electric and Power Company	SERC	1, 3
6.	Rick Purdy	Virginia Electric and Power Company	SERC	1, 3
7.	Chip Humphrey	Dominion Power Generation	SERC	5
8.	Jeff Bailey	Dominion Nuclear	SERC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Brandy Spraker	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Marjorie Parsons		SERC	6
2.	David Thompson		SERC	5
3.	DeWayne Scott		SERC	1
4.	Ian Grant		SERC	3
5.	Ryland Revelle		SERC	1
6.	Pat Caldwell		SERC	1
7.	Paul Palmer		SERC	5
8.	Lee Thomas		SERC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Wayne Johnson	Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

No Additional Responses

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Jason Marshall	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
2.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
3.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

4. Scott Brame	North Carolina Electric Membership Corporation	SERC	1, 3, 4, 5
5. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
6. Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Tim Beyrle	City of New Smyrna Beach	FRCC	4
2. Jim Howard	Lakeland Electric	FRCC	3
3. Greg Woessner	Kissimmee Utility Authority	FRCC	3
4. Lynne Mila	City of Clewiston	FRCC	3
5. Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6. Randy Hahn	Ocala Utility Services	FRCC	3
7. Stanley Rzad	Keys Energy Services	FRCC	1
8. Don Cuevas	Beaches Energy Services	FRCC	1
9. Mark Schultz	City of Green Cove Springs	FRCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	S. Tom Abrams	Santee Cooper	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Rene Free	Santee Cooper	SERC	1, 3, 5, 6
2. Tom Abrams	Santee Cooper	SERC	1, 3, 5, 6
3. Bridget Coffman	Santee Cooper	SERC	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17.	Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Merchant Operations	RFC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Group	Bill Crossland	ReliabilityFirst Protection Subcommittee										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Tex	PECO Energy	RFC	1
2.	Larry Rogers	Vectren	RFC	1
3.	Kathy West	Dayton Power & Light	RFC	1
4.	Michael Francis	American Transmission Co.	RFC	1

				1	2	3	4	5	6	7	8	9	10
19.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Daniels	American Electric Power	SPP	1, 3, 4, 5
2.	Louis Guidry	Cleco Power	SPP	1, 3, 5, 6
3.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7.	Stephen McGie	City of Coffeyville	SPP	NA
8.	Shannon Mickens	Southwest Power Pool	SPP	2
9.	James Nail	City of Independence, MO	SPP	3
10.	Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4
11.	Angela Summer	Southwestern Power Administration	SPP	1

				1	2	3	4	5	6	7	8	9	10
20.	Group	David Greene	SERC Protection and Controls Subcommittee										

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Warren	Big Rivers electric		
2.	Paul Nauert	Ameren		
3.	Rick Otte	EKPC		
4.	Bridget Coffman	Santee Cooper		
5.	David Greene	SERC RRO		

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
21.	Individual	William H. Chambliss, Member, Operating Committee	Virginia State Corporation Commisison										
22.	Individual	Michelle R. D'Antuono	Ingleside Cogeneration, L.P./Occidental Chemical Corporation					X					
23.	Individual	Anthony Jablonski	ReliabilityFirst										X
24.	Individual	Dale Fredrickson	Wisconsin Electric Power Company			X	X	X					
25.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				
26.	Individual	David Kiguel	David Kiguel								X		
27.	Individual	Catherine Wesley	PJM Interconnection		X								
28.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
29.	Individual	Barbara Kedrowski	Wisconsin Electric Power Company			X	X	X					
30.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
31.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
32.	Individual	Martyn Turner	LCRA Transmission Services Corp	X									
33.	Individual	Oliver Burke	Entergy Services, Inc.	X									
34.	Individual	Jonathan Meyer	Idaho Power Company	X									
35.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
36.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
37.	Individual	Chris Scanlon	Exelon	X		X	X	X	X				
38.	Individual	Michael Falvo	Independent Electricity System Operator		X								
39.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
40.	Individual	Karen Webb	City of Tallahassee					X					
41.	Individual	Bill Fowler	City of Tallahassee			X							
42.	Individual	Scott Langston	City of Tallahassee	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
43.	Individual	Christina Conway	Oncor Electric Delivery Company LLC	X									
44.	Individual	David Jendras	Ameren	X		X		X	X				
45.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
46.	Individual	Matthew Wykstra	Consumers Energy Company			X	X	X					
47.	Individual	PHAN, Si Truc	TransÉnergie Hydro-Québec	X									
48.	Individual	Bill Temple	Northeast Utilities	X									
49.	Individual	Chris Mattson	Tacoma Power	X		X	X	X	X				
50.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
51.	Individual	Steven Mavis	Southern California Edison Company	X		X		X	X				
52.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
53.	Individual	Texas Reliability Entity	Texas Reliability Entity										X
54.	Individual	John Brockhan	CenterPoint Energy Houston Electric LLC	X									
55.	Individual	Roger Dufresne	Hydro-Québec Production					X					
56.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
57.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					
58.	Individual	Russell Noble	Cowlitz PUD			X	X	X					
59.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
60.	Individual	Michael Moltane	ITC	X									
61.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
62.	Individual	Don Cuevas	Beaches Energy Services	X									
63.	Individual	Steve Lancaster	Beaches Energy Services	X									

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: The drafting team appreciates the entities below supporting the comments of others. Having single sets of comments with documented support greatly improves the efficiency of the standard drafting team (SDT). This format also ensures the drafting team has a clearer picture of the number of stakeholders supporting the same concerns or suggestions as the case may be.

Organization	Agree	Supporting Comments of "Entity Name"
Santee Cooper	Agree	Santee Cooper agrees with the SERC PCS Comments.
DTE Electric	Agree	RFC Protection Subcommittee
South Carolina Electric and Gas	Agree	SERC PCS
Beaches Energy Services	Agree	FMPA - Florida Municipal Power Agency

1. **Based on stakeholder input, the drafting team created a new definition for Composite Protection System to support the definition of Misoperation. The Slow Trip categories of Misoperation were also clarified. Do you agree with the new and revised definitions? If not, please provide specific suggestions for improvement.**

Summary Consideration: Approximately 56 commenters responded to this question about the proposed definitions. More than half agreed with the proposed changes. The majority of commenters responding "no" to the question had concerns that the SDT addressed through either a revision to the definition or a clarification in the Application Guidelines. The following is a summary of the significant issues and whether the concern resulted in a change or not.

There were three majority comment "themes" for this question that resulted in a change. Approximately 15 comments, supported by 43 individuals, had concerns about how to evaluate a "Slow Trip" with regard to the definition of "Misoperation." The SDT modified both "Slow Trip" categories of the definition for clarity. For example, "[a] Composite Protection System operation that is slower than required for a Fault condition if the duration of its operating time resulted in the operation of at least one other Element's Composite Protection System" would be a "Slow Trip" Misoperation. Second, about nine comments supported by 16 individuals either requested clarification to the definition of "Composite Protection System" and to clarify or add examples to the Application Guidelines concerning the definition. The SDT revised the definition of "Composite Protection System" and added several examples to the Application Guidelines. The last majority theme of comments from five individuals had general questions about the definitions of "Composite Protection System" and "Misoperation." Some questions raised by commenters resulted in a clarification to the definitions and Application Guidelines.

There were no majority comment themes that did not result in a change; however, there were five minority themes in the comments which did not result in a change and a number of other minority comments not summarized here. There were approximately two comments supported by 12 individuals that requested clarity in the use of "Composite Protection System" and "Protection System" in the Requirements. The SDT provided insight in the individual responses below which describe why or why not such changes improve clarity. One comment supported by eight individuals wanted to have an exclusion for dispersed generation resources (DGR) in the standard's Applicability. The SDT provide detail in the individual response that the DGR drafting team would address such an exclusion once this standard reaches industry approval. There were a number of questions about data reporting in one comment. Data reporting is being addressed in a "data request" consistent with the NERC Rules of Procedure, Section 1600, Request for Data or Information. This avoids having a Requirement for the reporting of Misoperations. Another comment requested the phrase "BES interrupting device" to be defined. The SDT did not define the phrase because it is widely understood by industry.

Last, there was a concern about undervoltage load shedding (UVLS) not being included in the standard. This will be addressed by the drafting team working on UVLS once this standard is approved by industry.

Organization	Yes or No	Question 1 Comment
Puget Sound Energy	No	a) Misoperation Definition #3 (Slow Trip - During Fault) would require the running of system studies to test for possible system instability. This (and/or other expectations) should be spelled out in the Application Guidelines. **Response:** The portion "[d]*elayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability…"* has been removed. Change made. b) Misoperation Definition #4 (Slow Trip - Other Than Fault) would also require the running of system studies to test for possible system instability. This (and/or other expectations) should be spelled out in the Application Guidelines. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made. c) For #2 & #4 sections of the Misoperation Definition as well as under Facilities (4.2.2) - UFLS/UVLS both should specifically be mentioned together. **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. d) It should be clarified that non-fault tripping protection schemes as described in PRC-004-3 do not include RAS/SPS (and that RAS/SPS will be covered in PRC-016).

Organization	Yes or No	Question 1 Comment
		Response: Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). An exclusion for RAS/SPS has been added to the Applicability section. Change made. e) It should be clarified in PRC-004-3 that UFLS/UVLS are not specifically part of the RAS/SPS definition (even though this is spelled out in the NERC glossary). Otherwise, it all can be quite confusing. **Response:** It would be inappropriate for the team to restate what is governed by the *Glossary of Terms used in NERC Reliability Standards* which may change in the future and could potentially require modifying an industry approved standard that contains such a clarification. No change made. f) In all six parts of the Misoperation Definition, the phrase "...where tripping for protection purposes is involved" could be included for clarity. **Response:** The drafting team has modified the definition of "Misoperation" to address this concern. Change made.
US Bureau of Reclamation	No	The Bureau of Reclamation (Reclamation) requests that the drafting team clarify the bounds of the Composite Protection Systems definition. Reclamation suggests that the drafting team update the Application Guidelines to provide an example of a Composite Protection System for a generator, a transformer, and a transmission line so that industry will have guidance on the scope of typical Composite Protection Systems. **Response:** The Application Guidelines section has been revised to add clarity concerning this issue. The examples were moved to the Application Guidelines. Change made.
FirstEnergy Corp	No	Composite Protection System as a new definition is unclear within the context of a Generating Unit as a BES Asset. Protection System, by definition, is already a composite of

Organization	Yes or No	Question 1 Comment
		the five identified components, as applicable. We do not understand the intent of adding the word Composite, or how it changes the current definition of a Protection System for a Generating Unit. **Response:** The Application Guidelines section has been revised to add clarity concerning this issue. The examples were moved to the Application Guidelines. Change made. The Misoperations drafting team understands the concern with the applicability of dispersed generation resources (DGR) to this standard. This drafting team is working with the DGR drafting team addressing standards with this concern under Project 2014-01 – Standards Applicability for Dispersed Generation Resources. In order to keep the sequence of the versions correct, the DGR drafting team will consider the exclusion in this standard once approved by industry. This should not be of great concern due to the implementation time of this standard and the need to bring in alignment with the work of the DGR drafting team. No change at this time.
PPL NERC Registered Affiliates	No	These comments are submitted on behalf of the following PPL NERC Registered Affiliates ("PPL"): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. Comments: The definition for 'Slow Trips' has been improved in the current draft of PRC-004-3, but still requires some revision. The first means by which slow tripping can be manifested, instability, is believed to pertain only to Transmission Systems. The second effect of slow tripping, bringing backup relays into play, does not pertain to generation plants. That is, opening the breaker via a backup relay of a generation plant means not that the primary device acted slowly, but that it did not function at all. This would be a Failure-to-Trip type of Misoperation of the primary relay. We understand that variation-of-tripping

Organization	Yes or No	Question 1 Comment
		is an issue of great importance for Transmission Owners (TOs), but it does not apply for generation plants (such as in the case of high speed tripping to limit system instability). Generator Owners (GOs) additionally do not necessarily have the installed equipment needed to analyze trip speed. Generation plants are not presently required to have high-speed disturbance monitoring equipment, and many plants still have electromechanical relays (i.e. no oscillograph function). Also, GOs often lack the design-level protection relay staff necessary to perform the activities described on pp. 23-24 of the Application Guidelines. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Duke Energy	No	(1) Duke Energy suggests rewording Slow Trip - Other Than Fault as follows: "A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed operation for a non-Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System." By replacing "clearing of a non-Fault" with "operation for a non-Fault", we feel this better describes the intent of a slow trip that is not a fault. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Florida Municipal Power Agency	No	FMPA appreciates the response to our comments, but, we do not believe our issues from our past comments have been resolved.

Organization	Yes or No	Question 1 Comment
		Regarding “Slow Trip”: FMPA agrees in concept with providing the ability to apply engineering judgment regarding what tripping “slower than required” may mean but believes there is too much ambiguity. We agree that “It is impractical to provide a precise tolerance ...”; however, If the standard is kept in this format, we support a clarification on the order of “fast enough to prevent harm to the protected equipment, undesired overtripping, or harm to stability.” **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made. FMPA believes “BES interrupting device” should be a defined term because it now drives the majority of the compliance activities associated with the standard. Specifically we believe with the way this device is characterized in the Application Guide is deficient. Devices that do not have “fault current interrupting capability” but have load interrupting capability, are often also used for protection functions in “Other than Fault” scenarios. Also, we note that fuses do not qualify as Protection System components although they meet Application Guide description of “BES interrupting device”. Confusion concerning treatment of fuses and the definition of BES Interrupting Device could lead to unintended consequences, such as a proliferation of use of fuses. **Response:** The drafting team asserts that the phrase “BES interrupting device” is widely understood by industry through both the absence of comments and the description in the Application Guidelines. No change made. FMPA still believes that the remaining definitions - Failure to Trip (During and Other than Fault) and Unnecessary Trip (During and Other than Fault) have similar difficulties to “Slow Trip”, wherein the standard provides the leeway for entities to apply judgment but that same leeway affords no way of supporting such judgment with evidence if an auditor disagrees with the interpretation.

Organization	Yes or No	Question 1 Comment
		Response: There is no criteria for judgment of accuracy within the Requirements. No change made. FMPA also believes that specifically excluding remote backup devices from the definition of Composite Protection System wrongly places a negative connotation on those typically lower voltage (100 - 161 kV) systems in which remote backup for a relay or breaker failure is "as-designed". We recognize that under the current format it will be difficult to avoid this issue - however if entities were able to develop their own Protection System Design Philosophy documents with this issue specifically addressed (see response to question 5 for more description of this proposed approach) as the criteria against which performance is measured, this problem goes away. **Response:** The drafting team has modified the definition of "Composite Protection System" and changed the reference to backup protection from an exclusionary statement to an inclusionary statement to address this concern. Change made.
SPP Standards Review Group	No	With the introduction of the term Composite Protection System, and especially considering the movement from Composite Protection System to Protection System in Requirements R1 and R2, additional confusion may have been incorporated into the standard than existed previously. If there is a way to eliminate the movement from one term to the other or develop a clearer transition from one to the other, it would be helpful to the industry. **Response:** The text involving Protection System component(s) (i.e., R1 or R2) is to provide a more granular look at the specific entity's protection whereas the text of Composite Protection System (i.e., Part 1.2 or 2.1) is referring to the broader condition where two or more entities jointly own a Protection System that makes up a Composite Protection System. No change made.

Organization	Yes or No	Question 1 Comment
Virginia State Corporation Commisison	No	Minor suggestion in Parts 1 and 2 "Faliure to Trip." I suggest changing the phrase "failure of a Protection System component" to "failure of any Protection System component." Although it may be a remote possibility, more than a single component may fail, while the Composite Protection System as a whole acts correctly. **Response:** The definition of Misoperation uses the singular form as only one Protection System component failure is required to be a qualifier in meeting the criteria. The term “any” is implicit in the statement. No change made.
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	No	Ingleside Cogeneration, L.P. (“ICLP”) agrees that the definition of “Composite Protection System” properly captures the concept proposed by the project team. It reflects an intent that a Misoperation is determined by evaluating the actual performance of the primary, secondary, and pilot systems in totality against the expected performance. Evaluations of individual schema failures are of little value when built-in redundancy takes over to protect the local system - exactly as the designers intended. **Response:** Thank you for your support of the definition. No change made. There is still discomfort with the definitions of “Slow Trip - During Fault” and “Slow Trip - Other Than Fault” - particularly in those cases where the design responsibility is out of our hands. For example, when PRC-024-1 takes effect, Generator Owners will have little control over the expected performance of voltage and frequency-responsive Protection Systems - provided the relays are set in accordance with the standard. This means that the definitions need to include a statement that any composite Protection System operation that reacts consistently with the parameters (settings) established in any other NERC standard cannot be a Misoperation. **Response:** If the operating time resulted in the operation of at least one other Element’s Composite Protection System, then it’s a “Slow Trip” Misoperation. If the Misoperation cause is determined to be a settings issue, then corrective action must be taken or a

Organization	Yes or No	Question 1 Comment
		declaration explaining why corrective actions are beyond the entity's control or would not improve BES reliability. No change made. Secondly, unless notified by the Transmission Planner or Planning Coordinator, ICLP will not know that the Misoperation of one of our Protection Systems will lead to BES "voltage or dynamic instability." The two definitions seem to recognize that the GO may not be in a position to be identify such critical Protection Systems, but can be read otherwise. Similar to the previous issue, we believe that as long as we correctly supply modeling data to the TP and PC in accordance with other NERC standards, the responsibility to identify susceptible Protection Systems remains with the planning entities. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
ReliabilityFirst	No	Throughout the draft standard (and definition of Misoperation), the term "Composite Protection System" is used while in other portions only the term Protection System is referenced. For example, within the definition of "Misoperation", items one through four use the term "Composite Protection System" while items five and six use the term "Protection System". **Response:** The term "Composite" was added to category 5 and 6 in the definition of "Misoperation." Change made. Another example is Requirement R1, Part 1.1 references the term "Protection System" while Part 1.2 references "Composite Protection System". ReliabilityFirst request the SDT's rationale on the appropriateness of the use of these terms. **Response:** The text involving Protection System component(s) (i.e., R1 or R2) is to provide a more granular look at the specific entity's protection whereas the text of Composite Protection System (i.e., Part 1.2 or 2.1) is referring to the broader condition where two or

Organization	Yes or No	Question 1 Comment
		more entities jointly own a Protection System that makes up a Composite Protection System. No change made.
Wisconsin Electric Power Company	No	We suggest revising #6 Unnecessary Trip -Other Than Fault: replace the 2nd sentence as follows: Current wording: "A Protection System operation that is caused by on-site maintenance, testing, ...is not a Misoperation" Suggested wording: "A Protection System operation that is related to on-site maintenance, testing, ... is not a Misoperation". This provides some flexibility to exclude operations not directly caused by on-site activity, but is a consequence of such activity. **Response:** The drafting team intends for this exclusion to apply only if the operation were directly initiated by on-site activities. A clarification was made to category 6.
Manitoba Hydro	No	(1) Manitoba Hydro believes that the definition of Misoperation needs to be re-written for the following reasons: a. It is not clear whether the six categories of Misoperations is exhaustive. The definition should be revised to clarify this. **Response:** The six categories are "exhaustive". The drafting teams contends that any Misoperation would fit within one of the categories. No change made. b. Under category 3, it is not clear if the cited example is the only type of Misoperations. **Response:** The portion "[d]*elayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability…"* has been removed. Change made. More explicit criteria has been provided to add the necessary clarity.

Organization	Yes or No	Question 1 Comment
		c. Use of the phrase “slower than required” in category 3 and 4 of the definition is unclear and does not capture the intended meaning identified in the Application Guidelines. The Guidelines state that “required” actually means as intended by the owner. Thus, this terminology should be used. **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made. d. Based on the numerous examples in the Guidelines of what is and is not a “Misoperation”, as well as references in the Guidelines to the effect that SMEs recognize that judgment must be used, the definition itself should clearly incorporate the notion of judgment by the owner. While the first sentence of the definition refers to intention, it does not specify whose intention (manufacturer, designer, operator..?) **Response:** The drafting team has modified the definition of “Misoperation” to address this concern. Change made. The proposed definition of “Slow Trip” simplifies the criteria; therefore, simplifying the determination. The Application Guidelines has been updated to clarify the intent of the drafting team in using the word “intended” in the definition of “Misoperation.” e. The sentences about component failure are out of place given that the definition of Composite Protection System is the total system, not individual components, and given that the first sentence of the definition refers specifically to failure of the Composite Protection System. **Response:** The intent is to provide clarity that a single component failure is not a Misoperation so long as the overall performance of the Composite Protection System is correct. No change made.

Organization	Yes or No	Question 1 Comment
		f. The word "intended" has been replaced with "required" even though the Application Guideline states that the term "required" is intended to refer to the objective of the owner. If this is the intended meaning, then the standard should use the wording "as intended by the owner". The words "as required" are too vague and may be interpreted to mean as required to ensure the reliability of the BES. (Could it also mean as required by the designer / manufacturer or some other entity?) **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. (2) Revise the definition of Composite Protection System to "The total complements of the Protection System(s) that function collectively to protect an Element, such as A and B system, any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded." **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. A redline of the commenter's proposal above is provided using **blue with underline** for additions and ~~red with strikethrough~~ for deletions to illustrate the requested revision: "The total complement**s** of the Protection System(s) that function collectively to protect an Element, such as **A and B system,** any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded."
Flathead Electric Cooperative, Inc.	No	I do not like adding composite to the definition of protection system. This seems to broaden what is understood as a protection system and may impact testing and maintenance programs unnecessarily. I suggest sticking with the way it was before this redline change. **Response:** The drafting team is not modifying the current defined term Protection System, but defining a newly proposed term. No change made.

Organization	Yes or No	Question 1 Comment
American Electric Power	No	AEP recommends replacing "high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability" with "the lack of high-speed performance resulted in voltage or dynamic instability". The draft does not specify who is responsible to perform the identification, and adding "Planning Authority" would create a de facto TPL requirement. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Independent Electricity System Operator	No	We do not see the need to create a defined term "Composite Protection System". By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is redundant. In the comment report, it is indicated that 4 commenters representing about 24 individuals requesting clarification of the term "composite Protection System". This represents a very low percentage of the total number of commenters and individuals, which should not be the basis for proposing a new term which is redundant. We suggest to remove this defined term. **Response:** The reason for proposing the newly defined term, "Composite Protection System," is found in the Application Guidelines under the heading "Definitions." No change made.
Public Service Enterprise Group	No	We agree with the definition of Composite Protection System, but we believe that the categories definition of Misoperation could be improved. The standard does not address situations where one cannot determine whether the Protection System operated correctly or whether a Misoperation occurred. • Without evidence of a Fault associated with a trip, it is possible that Normal Clearing occurred, although there may be no evidence to support or reject that conclusion.

Organization	Yes or No	Question 1 Comment
		• Without evidence of a Fault associated with a trip, it is also possible that a category 5 (Unnecessary Trip - During Fault) or category 6 (Unnecessary Trip - Other Than Fault) Misoperation occurred; however, there may be no evidence to support or reject either reporting category. In order to address a situation when the operation of a Protection System cannot be determined to be a correct operation or a Misoperation, we believe a seventh Misoperation category should be considered: "Unclassified Trip: Any trip that (a) cannot be confirmed as the correct operation of the Protection System and (b) for which the evidence is not sufficient to place the trip into another Misoperation category." **Response:** The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. See the Application Guidelines under the heading "Requirement R1." This will cause all such trips to be consistently investigated as Misoperations. We understand that many of these Misoperations may result in an undetermined cause.
Tacoma Power	No	In the definition of Misoperation, Unnecessary Trip - Other Than Fault, change "...caused by..." to "...related to..."In the definition of Misoperation, there may be some ambiguity/overlap in determining if some Misoperations are due to a Slow Trip or an Unnecessary Trip when Protection Systems are found not to have been adequately

Organization	Yes or No	Question 1 Comment
		coordinated. It is suggested that something like the following change be made to Slow Trip - During Fault and Slow Trip - Other Than Fault: Change "...or resulted in the operation of any other Composite Protection System..." to something like "...or a Protection System component failure resulted in the operation of any other Composite Protection System..." Inadequately coordinated relay settings would then more clearly fall under either Unnecessary Trip - During Fault or Unnecessary Trip - Other Than Fault. The only other remedy would be to categorize the Misoperation based upon the corrective action taken. (It should be noted that this ambiguity/overlap is only an issue if Misoperations must later be coded during a NERC data request.) **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. In the definition of Misoperation, Slow Trip - Other Than Fault, consider removing the reference to "...voltage or dynamic instability..." It seems that these issues may be more related to Fault conditions. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Southern California Edison Company	No	There continues to be a lack of clarity in the definition. The standards drafting team has created a term that does not provide clear means of compliance for the industry. **Response:** The "Misoperation" definition has been modified to address this issue. Change made.
Xcel Energy	No	1) The definition for Composite Protection System could be clearer. For example, are the relays deployed at all ends of a transmission line for the protection of that line considered a part of one Composite Protection System? Does the presence or

Organization	Yes or No	Question 1 Comment
		absence of a communications-assisted scheme change which relays would comprise the Composite Protection System? **Response:** Yes, relays deployed at all ends of a transmission line, which is an Element, that function collectively to protect that line are considered a part of the line's Composite Protection System. The presence or absence of a communications-assisted scheme does not change the application of the proposed definition. The Application Guidelines section has been updated to address this issue. Change made. 2) The definition of Composite Protection System should be modified to account for all of the elements that may or may not operate to protect an element, excluding breaker failure protection. Breaker Failure protection should be considered its own zone of protection. Suggested change as follows: The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded. Breaker failure protection should be considered as protecting its own specific breaker element. **Response: This portion of the Application Guidelines has been revised based upon the suggestion. Change made.** A redline of the commenter's proposal above is provided using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: "The total complement of the Protection System(s) that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded. **Breaker failure protection should be considered as protecting its own specific breaker element**." 3) We have two issues driving our negative vote. The first issue is that high speed performance requirements for identified Composite Protection Systems are not defined or

Organization	Yes or No	Question 1 Comment
		controlled by a single entity with regional grid performance knowledge, such as Transmission Planning. Without centralized accountability to identify performance requirements for specified systems, settings will be installed according to the PRC-001 coordinated settings implemented by the BA, and TO or GO system owners. These settings have been coordinated with the applicable entities. Transmission Planning is the entity that should be cognizant of settings required to maintain system stability under various fault conditions, and notify TO system owners of these requirements for inclusion in PRC-001 coordination. This coordination needs to be identified, tracked, and proper timelines for implementation identified. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made. 4) The second issue driving our negative vote is the lack of a time requirement tied to when a "previously identified" high-speed performance need has to be implemented. For example, under the Slow Trip - During Fault, the phrase " ...if high-speed performance was previously identified..." has no time horizon to make this an effective requirement. If a high speed, 3 cycle fault clearing requirement was identified by e-mail the previous day, and the device was not reset immediately, and a subsequent event caused the device to operate at 30 cycles, a Misoperation would result. Instead, a process by which requirements are identified by the planner, allowing an defined period for implementation, should be required. This could be accomplished by either adding Transmission Planning as an applicable entity with notification requirements defined in the requirement language, or including the GO/TO/Distribution provider as a partner in this process in another standard, such as PRC-001 or the TPL series. Proposed rewording is as follows: Misoperation: The failure of a Composite P0rotection System to operate as intended and previously coordinated. Any of the following is a Misoperation:

Organization	Yes or No	Question 1 Comment
		Slow Trip - During Fault - A Composite Protection System operation that is slower than for a Fault condition for which it is designed and coordinated. Delayed clearing of a Fault condition is a Misoperation if it resulted in the operation of any other Composite Protection System. Slow Trip - Other Than Fault - A Composite Protection System operation that is slower than required for a non-Fault condition for which it is designed and coordinated, such as a power swing, undervoltage, overexcitation, or loss of excitation. Delayed clearing of a non-Fault condition is a Misoperation if it resulted in the operation of any other Composite Protection System. And similar edits to all other fault definitions in the document, removing the "...previously identified..." language. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Texas Reliability Entity	No	Texas RE is concerned that the revised definition of Misoperation is limited to failure of a Composite Protection System, and that this standard does not require investigation and mitigation of all Protection System operations/failures to operate when they are sub-parts of a Composite Protection System. We submit that any failure to operate as designed should be investigated and mitigated, even if another part of the Composite Protection System covered for the malfunctioning component/system. **Response:** The Composite Protection System definition is based on the principle that an Element's multiple layers of protection are intended to function collectively. This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the overall performance of an Element's total complement of protection should be considered while evaluating an operation.

Organization	Yes or No	Question 1 Comment
		The purpose of having the definition of Composite Protection System is to promote reliability and not to penalize entities for implementing redundant protection (e.g., primary and secondary protection). A failure of the primary system when secondary system operates correctly is not a Misoperation because the Composite Protection System operated correctly to protect the given Element. The Application Guidelines section has been updated to address this issue. Change made.
CenterPoint Energy Houston Electric LLC	No	CenterPoint Energy agrees with the new definition for Composite Protection System and believes it is needed to support consistent misoperations reporting. However, we suggest additional clarifications for the two Slow Trip categories of Misoperation definitions that were revised to address high-speed performance. The second sentence of the two Slow Trip categories of Misoperation definitions states: ‘Delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or resulted in the operation of any other Composite Protection System’. We recommended changing this sentence to state the following: ‘If the Composite Protection System is comprised of two, or more, independent high-speed schemes, delayed clearing of a Fault condition is a Misoperation if high-speed performance was previously identified as being necessary to prevent voltage or dynamic instability, or if high-speed performance was previously identified as being necessary for coordination with other Composite Protection Systems.’ **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made.
Indiana Municipal Power Agency	No	We see no alternative other than to install SOE equipment and/or Disturbance Monitoring Equipment and/or Digital Fault Recorders to monitor the Composite Protection System

Organization	Yes or No	Question 1 Comment
		during operations/Misoperations of BES interrupting devices. With the current definition of Misoperation, especially the Slow Trip definitions, it will be crucial to the investigation to have exact Protection System parameters and operation times prior to, during, and immediately following any operation on a BES interrupting device. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made. In short any Protection System element (any device subject to PRC-005) must now be logged, recorded, and archived in order for a Registered Entity to be able to go back and show that their Protection System/Composite Protection System operated as designed and did not contribute to a Misoperation on either their own BES interrupting device and/or an adjacent Registered Entity's BES interrupting device. This will be a considerable expense for smaller GOP's and DP's to install, operate, and maintain the equipment and archive the data and records required to meet the burden of these proposed definitions. **Response:** The proposed standard is not prescriptive and provides the applicable entities flexibility in choosing how they log, record, and archive data and records. No change made.
Tri-State Generation and Transmission Association, Inc.	No	We believe that the term "local backup" includes breaker failure relaying, but it appeared at the webinar that the drafting team does not intend for breaker failure relaying to be included in the definition of Composite Protection System. We recommend that "local backup" be removed from the definition or changed to "local backup (excluding breaker failure protection)." **Response: This portion of the Application Guidelines has been revised based upon the suggestion. Change made.**
Liberty Electric Power LLC	No	The maintenance exclusion should include failure to trip as well as trip. Take for example a deliberate roll of a lock out relay as a unit comes offline to test the system. Under the

Organization	Yes or No	Question 1 Comment
		definition if the test caused an early trip it would not be an misoperation. But it is unclear if a failure to trip during the test would be a misoperation. **Response:** The drafting team has modified the definition of "Misoperation" to address this example. Change made.
Florida Power & Light	Yes	No comments on the modified "Composite Protection System" definition. However, confusion may result in trying to determine whether an item fits into Misoperation Category 1 "Failure to Trip-During Fault" or into the Category 3 "Slow Trip-During Fault" definition. In both cases, the fault is likely be isolated by remote backup protection schemes. Consider combining Categories 1 and 3. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made. The Composite Protection System will not have operated for a Failure to Trip; whereas, for a Slow to Trip Composite Protection System operation, an operation would have occurred. Either way both are a Misoperation. Also, regarding Category 6 "Unnecessary Trip-Other that Fault," the included wording is somewhat confusing. Consider revising to: "Spurious operation of a protection system in the absence of a fault condition on the power system it is designed to protect." **Response:** The drafting team declined to use "Spurious…" as suggested, but made other modifications to the Unnecessary Trip – Other Than Fault portion of the definition of "Misoperation." Change made.
Southern Company: Southern Company Service, Inc.; Alabama Power Company;	Yes	Yes, provided that it is made plain that, for the purposes of reportability, the failure or misoperation of an individual component of the Composite Protection System is not to be considered a reportable Misoperation when the Composite Protection System taken collectively functionally did not misoperate. Without this clarification, it is still confusing to

Organization	Yes or No	Question 1 Comment
Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		state that the failure (misoperation) of an individual component of a Composite Protection System is not a misoperation. We suggest adding "reportable" to all occurances of the phrase "is not a misoperation" to read "is not a reportable Misoperation" where the phrase occurs in the draft standard (12 occurances). **Response:** The intent is to provide clarity that a single component failure is not a Misoperation so long as the overall performance of the Composite Protection System is correct. No change made. Reporting has been removed from the standard; therefore, adding this language would not add clarity. No change made. The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[2] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made. The definition of Misoperation, items 5 and 6 need to have the word Composite inserted between unnecessary and Protection. **Response:** The drafting team has modified the definition of "Misoperation" to address this concern. Change made.
ACES Standards Collaborators	Yes	The definition of Misoperation is much improved. We thank the drafting team for proposing a definition for Composite Protection System. It adds clarity to the standard. **Response:** Thanks you for your support.

[2] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Organization	Yes or No	Question 1 Comment
American Transmission Company	Yes	ATC agrees with the new and revised definitions, but recommends additional clarification around Slow Trip. Would a study be needed to indicate where high-speed performance was previously identified for a Slow Trip? The Slow Trip definitions infer that in order to correctly or incorrectly declare a Misoperation, a study would need to occur. Such study would need to pre-date the operation. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made.
Entergy Services, Inc.	Yes	There are a lot of protective relays that protect one element that sense the same parameter. For example, the Generator has a Generator differential relay, an overall differential relay, an overcurrent relay. If the Generator differential fails to actuate but the overall differential relay or the overcurrent actuates, does that mean the Composite Protection System did not misoperate? **Response:** In the example above, this is not a Misoperation of the Composite Protection System. The Application Guidelines have been revised to add clarity concerning this issue. Change made. The definition of Composite Protection System is still vague to this. Suggest the below definition: The total complement of the Protection System(s), <u>with respect to the protective relay of interest,</u> that function collectively to protect an Element, such as any primary, secondary, local backup, and communication-assisted relay systems. Backup protection provided by a remote Protection System is excluded. **Response:** The definition of Composite Protection System and the associated Application Guidelines section has been modified to improve clarity. Change made.

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	Yes	Please clarify the following; the composite protection system also includes the potential transformers, current transformers, battery bank and charger? **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Exelon	Yes	We support the definition for Composite Protection System. **Response:** Thank you for your support.
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Tennessee Valley Authority	Yes	
ReliabilityFirst Protection Subcommittee	Yes	
SERC Protection and Controls Subcommittee	Yes	
David Kiguel	Yes	
PJM Interconnection	Yes	

Organization	Yes or No	Question 1 Comment
Muscatine Power and Water	Yes	
LCRA Transmission Services Corp	Yes	
Idaho Power Company	Yes	
Kansas City Power & Light	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
Consumers Energy Company	Yes	
TransÉnergie Hydro-Québec	Yes	
Northeast Utilities	Yes	

Organization	Yes or No	Question 1 Comment
Seminole Electric Cooperative, Inc.	Yes	
Hydro-Québec Production	Yes	
Cowlitz PUD	Yes	
ITC	Yes	

2. **Based on stakeholder input, the drafting team modified the previous Requirement R1 to clarify responsibilities where two or more entities share ownership of a Protection System. The proposed Requirement R2 determines when other entities are notified and Requirement R3 now clarifies that the notified entity has the greater of 60 calendar days from notification or 120 calendar days from the BES interrupting device operation. Do you agree this modification clarified the performance for notification (R2) and the notified (R3)? If not, please provide specific suggestions for improvement.**

Summary Consideration: Of the 53 commenters that responded to this question regarding the first three Requirements in the standard, more than two-thirds support the standard drafting team's (SDT) revisions and approach. The majority of commenters responding "no" to the question had concerns that the SDT addressed with a revision to the standard. The following is a summary of the significant comments and whether the concern resulted in a change or not.

There were approximately two majority comments, both of which resulted in a revision to the standard. Two comments supported by 26 individuals noted that the one or more of the Measures were insufficient. The SDT provided additional detail in the Measures. Second, approximately three comments supported by ten individuals raised concerns about notification of other owners. To address these concerns, the SDT revised Requirement R2, 2.1, to read: "notification of the operation shall be provided to the other owner(s) that share *Misoperation identification responsibility* for the Composite Protection System." This is intended to allow the initiating entity to identify and notify the appropriate owner that needs to review the BES interrupting device operation for Misoperation.

A minority issue identified by two individuals revealed a significant gap in the standard for the case of a BES interrupting device that failed to operate. If this condition occurred, there would have been no specific performance for an entity to initiate the Requirement(s). To address this, the SDT revised Requirement R2 by creating two discrete conditions for notification. For the case of the BES interrupting device failing to operate, a remote BES interrupting device would have operated. It would be this device owner in Requirement R2 that would have an obligation to notify the other owner for which backup protection was provided to close the gap.

There were two significant majority issues that did not result in a change. The first concerns joint owners and there were approximately eight comments supported by 23 individuals that requested either a Requirement to have agreements between joint owners or how to address cases where the equipment is owned by the same entity, but different functions. The SDT provided detailed responses below for each of these comments. In general, if a single entity can meet the standard's objectives and support its compliance under Requirement R1, there is no need to make notifications; however, Requirement R2 is provided to ensure that other owners or entities that share Misoperation identification responsibility for the Composite Protection System are notified.

Other minority comments were too numerous to list in this summary, but are detailed in individual responses, below. Some include confusion about notifications and the time periods. Others revealed confusion between identifying the Misoperation and identifying the cause of the Misoperation. One comment requested special handling for extenuating circumstances and another requested the Distribution Provider to be excluded from the standard's Applicability.

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Forum	No	To support the movement away from zero tolerance standards and towards the Reliability Assurance Initiative which recognizes appropriate risks to the Bulk Electric System, the NSRF proposes the 60 and 120 calendar day time frames be removed. Entities can be assessed to determine if they are identifying misoperations and correcting issues without daily timeframes. Writing in daily timeframes forces the audit of timeframes placing a documentation burden on entities that does nothing to support reliability. Administrative accounting for timeframes shifts the focus of the reliability activity away from identifying and correcting reliability issues to accounting. As one alternative, the drafting team could go back to the fundamental position of reporting progress quarterly similar to the current PRC-004 standard. Another alternative is, if the drafting team must impose daily timeframes, daily timeframes would be implemented only after the development of a nationwide database similar to the TADs database that includes internal controls (such as reminders) similar to the RAPA database that allows entities to enter and track all of the required information necessary to meet the PRC-004-3 standard within the database, thus reducing the some of the administrative burden.

Organization	Yes or No	Question 2 Comment
		Please note that the PRC-005-2 drafting team recognized the trap of writing a standard that imposes accounting for timeframes understanding that schedules change and events occur which could cause an entity to miss its schedule by days or weeks. See below: Excerpt from PRC-005-2 supplemental reference: Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. The reliability benefit of the NERC standard is to identify misoperations and to take corrective actions. This can be achieved without the daily accounting burden imposed by the current writing of the standard. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made.
FirstEnergy Corp	No	R1 and R2 refer to identification and notification "... within 120 calendar days of the BES interrupting device operation ...". Currently, submittals to the Regional Entity are due 60 days following the end of a quarter, which could conceivably place it up to 150 days following an event. Besides having to move up the review of Protection System operations, what Evidence will be required to prove the 120 day identification and notification? **Response:** The RSAW will provide the audit approach to determining compliance. Acceptable evidence is listed in each Requirement's Measure. No change made.

Organization	Yes or No	Question 2 Comment
PPL NERC Registered Affiliates	No	The expression, "identify whether its Protection System component(s) caused a Misoperation when," in R1 should be changed to, "identify whether (a) its Protection System component(s) caused a Misoperation, (b) functioned correctly or (c) a Misoperation cannot be ruled-out, when." NERC acknowledges in R4 that many months or even more than a year may be needed to authoritatively classify a relay operation, and this possibility is noted also in R2.2, but R1 requires passing Misoperation-vs.-no Misoperation determination within 120 days. It was stated in the 2/20/2014 Protection Systems Misoperation Webinar that such situations should be addressed by initially assuming a Misoperation, and later ask that the coding be changed if this proves not to be the case. The PPL NERC Registered Affiliates submit (per the guidelines issued by RFC) that in the absence of evidence, a Misoperation should not be assumed. **Response:** The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made.
Dominion	No	The calendar day time keeping requirements create additional burden on entities to track and maintain additional records for each entities timeline dates; especially R3 where the allotted time to identify the misoperation is dependent on when someone else notifies them. The 60 calendar day time frame is reasonable, but creates potential for non-compliance just because of an arbitrary date. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made.

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency	No	FMPA believes there are still ambiguities regarding the responsibility where to or more entities share ownership of a Protection System. Specifically as R1 relates to R2 the language reads in a way that seems to imply entities are required to wait to provide notification of the ongoing investigation to one another, which we believe is not the intent. **Response:** It is not the intent to require entities to wait to provide notification. A period of 120 calendar days after a BES interrupting device operation is provided for the BES interrupting device owner to perform Requirement R2. If the BES interrupting device owner determines from parts 2.2 and 2.3 that a notification is warranted they have the remainder of the 120 calendar day period to make notification. They do not have to wait for the 120 calendar day period to expire before making notification. No change made. Requirement R2 has been redrafted for clarity but the intent remains the same. Furthermore please clarify; where BES interrupting devices are associated with multiple Composite Protection Systems; Does 1.2 refer to the Composite Protection System which is believed to have operated or to all Composite Protection Systems associated with the BES Interrupting device (which may or may not be owned by the same entity)? **Response:** Requirement R1, Part 1.2 is referring to the Composite Protection System that initiated the BES interrupting device operation. No change made.
Virginia State Corporation Commisison	No	R1 remains very unclear to me. The text requires a TO, GO or distribution provider to "identify whether" its component caused a misoperation, but Subparagraph 1.3 requires, as a necessary condition to such identification that the "BES interrupting device owner [has] identified" that its component caused the failure. This is circular. **Response:** Parts 1.1 through 1.3 are the criteria for which BES interrupting device operations have to be reviewed under R1 within 120 calendar days. Part 1.3 says “caused the BES interrupting device(s) operation” not caused the failure. If all three are true, then the entity must review (i.e., determine) whether its Protection System component(s) caused a

Organization	Yes or No	Question 2 Comment
		Misoperation. Similarly, Requirement R2 uses the same concept, but for determining the notification of others. No change made.
ReliabilityFirst	No	The term “BES interrupting device” is used throughout Requirements R1, R2 and R3 though it is only defined within the Application Guidelines section. In order to provide clarity and avoid potential interpretations of what constitutes a “BES interrupting device”; ReliabilityFirst recommends the SDT propose this as a new definition which would be added to the NERC Glossary of Terms. ReliabilityFirst recommends the following definition from the Application Guidelines for consideration: “BES Interrupting Device - A BES Element, typically a circuit breaker or circuit switcher that has the capability to interrupt fault current.” **Response:** The drafting team asserts that the phrase “BES interrupting device” is widely understood by industry through both the absence of comments and the description in the Application Guidelines. No change made.
Wisconsin Electric Power Company	No	There appears to be a gap between R1 and R2 for the case when an interrupting device operates, but the interrupting device owner does not own any part of the Protection System(s) that tripped or may have tripped the device. The assumption in the draft is that the interrupting device owner also owns a portion of the Protection System, but this may not always be true. **Response:** The drafting team asserts that according to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). No change made. Requirement R2 has been modified to address these concerns. Change made.

Organization	Yes or No	Question 2 Comment
David Kiguel	No	The standard should require that the Connection Agreement(s) among owners must address the procedures and potential dispute resolution for the case of 2 or more owners involved in the Misoperation investigation and CAP. **Response:** The drafting asserts this suggestion is administrative in nature and does not support reliability overall. The proposed standard mandates the necessary obligation for each entity of the jointly owned Protection System. Development and implementation of a Corrective Action Plan (CAP) to correct the Protection System component(s) of an identified Misoperation is incumbent upon the entity that owns the component. No change made.
Muscatine Power and Water	No	To support the movement away from zero tolerance standards and towards the Reliability Assurance Initiative which recognizes appropriate risks to the Bulk Electric System, MP&W proposes the 60 and 120 calendar day time frames be removed. Entities can be assessed to determine if they are identifying misoperations and correcting issues without daily timeframes. Writing in daily timeframes forces the audit of timeframes placing a documentation burden on entities that does nothing to support reliability. Administrative accounting for timeframes shifts the focus of the reliability activity away from identifying and correcting reliability issues to accounting. As one alternative, the drafting team could go back to the fundamental position of reporting progress quarterly similar to the current PRC-004 standard. Another alternative is, if the drafting team must impose daily timeframes, daily timeframes would be implemented only after the development of a nationwide database similar to the TADs database that includes internal controls (such as reminders) similar to the RAPA database that allows entities to enter and track all of the required information necessary to meet the PRC-004-3 standard within the database, thus reducing the some of the administrative burden.

Organization	Yes or No	Question 2 Comment
		Please note that the PRC-005-2 drafting team recognized the trap of writing a standard that imposes accounting for timeframes understanding that schedules change and events occur which could cause an entity to miss its schedule by days or weeks. See below: Excerpt from PRC-005-2 supplemental reference: Also of note is the Table's use of the term "Calendar" in the column for "Maximum Maintenance Interval." The PSMT SDT deemed it necessary to include the term "Calendar" to facilitate annual maintenance planning, scheduling and implementation. This need is the result of known occurrences of system requirements that could cause maintenance schedules to be missed by a few days or weeks. The PSMT SDT chose the term "Calendar" to preclude the need to have schedules be met to the day. The reliability benefit of the NERC standard is to identify misoperations and to take corrective actions. This can be achieved without the daily accounting burden imposed by the current writing of the standard. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made.
American Electric Power	No	1) AEP recommends revising R1 section 1.2 as follows to recognize that a BES interrupting device may be part of multiple Composite Protection Systems: "The BES interrupting device owner owns all or part of the Composite Protection System(s); and". **Response:** Requirement R1, Part 1.2 is referring to the Composite Protection System that initiated the BES interrupting device operation. No change made. 2) AEP recommends revising R2 section 2.1 as follows: "The BES interrupting device owner shares the Composite Protection System(s) ownership with any other entity; and".

Organization	Yes or No	Question 2 Comment
		Response: Requirement R2, Part 2.1 is referring to the Composite Protection System that initiated the BES interrupting device operation. Requirement R2 has been modified. The previously drafted R2 Part 2.1 is now R2 Part 2.1.2. Change made. 3) AEP recommends adding the following footnote to the "entity" reference in R2 section 2.1: "In this context, "entity" denotes functional entity. A Composite Protection System owned by different functional entities within the same registered entity satisfies the R2 section 2.1 criteria." **Response:** A Composite Protection System owned by different functional entities within the same registered entity does not necessarily satisfy the R2 section 2.1 criteria. For example, if the same personnel within a registered entity perform the Misoperation identification for both the GO and TO functions, then the Misoperation identification would be completely covered in Requirement R1, and therefore notification would not be required. However, if the Misoperation identification is handled by different groups, then notification would be required because the Misoperation identification would not necessarily be completely covered in Requirement R1. Part 2.1 of Requirement R2 has been modified to address this concern. Change made. 4) AEP recommends adding the following footnote to the "entity's" reference in the first bullet of R5: "In this context, "entity" denotes functional entity". **Response:** The drafting team does not agree the suggestion provides additional clarity. Entity customarily denotes functional entity. No change made. 5) AEP recommends adding the following footnote to the "120 calendar days" reference in R2 and R3: "This timeframe may be extended, for operations occurring within a specified time period, by the Regional Entity if it determines that extenuating circumstances such as a natural disaster make it impractical to complete R1 or R2 within the allotted timeframe". **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (time frames) of a Reliability Standard in unique extenuating

Organization	Yes or No	Question 2 Comment
		circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.
Exelon	No	Please address who takes lead responsibility for R1 when the associated BES interrupting device has multiple owners (i.e. single breaker that has multiple owners, two breakers associated with a line or generator on a ring bus with a different owner for each breaker, a three-terminal line with different owners for each terminal). Perhaps some additional examples in the Application Guidelines focusing on this situation would be helpful in reducing this confusion. Otherwise we have no concerns with R1. **Response:** While a BES interrupting device may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. For R2 and R3, the date timeframes for a shared responsibility Protection System to a common interrupting device short cycles the non-owner of the interrupting device. A suggestion for shared responsibly; With R2 - the BES device owner should notify the Other Protection System owners within 30 calendar days of the operation and the device owner has 120 days calendar days to identify if it's Protection System caused a misoperation. For R3, the notified Protection owner should then have 120 from notification to identify if its Protection System misoperated. This time frame for R3 would provide the non-owner sufficient time for any scheduled outages to make a determination.

Organization	Yes or No	Question 2 Comment
		Response: Notification in Requirement R3 starts the period for the Protection System component owner to begin its investigation. If the BES interrupting device owner officially notifies other Protection System component owners pursuant to Requirement R2 when there may be no need to do so, it will create an unnecessary compliance obligation for the other owners (i.e., upon notification), especially when there is little possibility that another owner's Protection System component(s) caused a Misoperation. The requirements do not preclude the initial entity that is reviewing the operation from working with the other owners and when necessary, make the official notification within 120 calendar days. This is the concept the drafting team is employing in Requirement R3 which considers the informal communication and the exchange of information. Should an entity receive notification, it always has a minimum of 60 calendar days and probably has a good idea of the problem; otherwise, if a notification (i.e., official notification) happens early on, the entity is now subject to compliance under Requirement R3. If the entity has not ruled out a Misoperation, it should assume it is a Misoperation, at which time, Requirement R4 will enable the entity to continue its investigation into the cause or no cause found. No change made.
Xcel Energy	No	1) There appears to be a potential gap if a Composite Protection System wholly owned by one entity experiences a Failure to Trip, and only interrupting devices wholly owned by another entity operate. 2) Propose wording change for R1 through R3 as follows: "R1 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its Associated Composite Protection System component(s) Misoperated when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"; "R2 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES

Organization	Yes or No	Question 2 Comment
		interrupting device operation, notify the other owner(s) of the Associated Composite Protection System of the operation when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"; and "R3 - Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Associated Composite Protection System component(s) caused a Misoperation. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]" **Response:** Requirement R2 has been modified to address these concerns. Change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: "R1 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, identify whether its **Associated** **Composite** Protection System component(s) ~~**caused a Misoperation**~~ **Misoperated** when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"; "R2 - Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated shall, within 120 calendar days of the BES interrupting device operation, notify the other owner(s) of the **Associated** **Composite** Protection System of the operation when: [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"; and "R3 - Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its **Associated** **Composite** Protection System component(s) caused a

Organization	Yes or No	Question 2 Comment
		Misoperation. [Violation Risk Factor: Medium][Time Horizon: Operations Assessment, Operations Planning]"
Texas Reliability Entity	No	There are several cases in the ERCOT Region where Company A owns the interrupting device and Company B owns the Protection System. In these cases, subpart 1.2 for R1 and subpart 2.1 for R2 do not apply. The language for Requirements R1 and R2 is written such that all of the subparts (1.1, 1.2, and 1.3 for R1 and 2.1, 2.2, and 2.3 for R2) must apply for the entity to initiate the analysis of the operation or notification. We would suggest modifying the language for R1 and R2 to say that the Requirement applies if one or more of the subparts apply. **Response:** The drafting team asserts that according to definition of Protection System which became effective April 1, 2013, the BES interrupting device owner owns a component of the Protection System, namely the trip coil(s) of that BES interrupting device (at a minimum). No change made.
Hydro-Québec Production	No	For the requirement R1, the other owner of the protection system shall share any information it has that could be used by the owner of the interrupting device to determine the cause of the misoperation of the interrupting device owner's protection system. For the requirement R2, the owner of the interrupting device shall share any information it has that could be used by the other owner of the protection system to determine the cause of the misoperation. **Response:** The drafting team agrees this is a best practice; however, it is not useful having a Requirement for each entity to share information. The way the Requirements are written, it is in the best interest of all parties (i.e., jointly owned Protection Systems) to share or communicate information about operations which meet the criteria for Requirement R1 and R2. Having such a Requirement is administrative and provides little, if any, reliability benefit. No change made.

Organization	Yes or No	Question 2 Comment
Tri-State Generation and Transmission Association, Inc.	No	We generally agree but we have some concerns about multiple entity ownership of different Protection System components compared to joint ownership of individual components. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. A change was made to Requirement R2, 2.1, "notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System" to address this concern. Change made.
Northeast Power Coordinating Council	Yes	We agree with the requirements as revised, but do not agree with Measures M2 and M3. a. Measure M2: The performance target is that the responsible entity notified the other owner(s) of the Protection System of the operation of the BES interrupting device when the conditions in Parts 2.1 to 2.3 are met. **Response:** The Measures have been updated. Change made. b. Measure M3: The performance target is that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when notified by the other owner of the Protection System of the BES interrupting device that operated. **Response:** The Measures have been updated. Change made.
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power	Yes	If the drafting team feels that this issue needs to be specifically stated in the Standard then the approach is acceptable. However, since there is no evidence that separate entities have not been doing due diligence in investigating and correcting misoperations, the addition of the various timelines serve only to generate additional paperwork and administrative burden.

Organization	Yes or No	Question 2 Comment
Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		If the drafting team feels that this issue needs to be specifically stated in the Standard then the approach is acceptable. However, since there is no evidence that separate entities have not been doing due diligence in investigating and correcting misoperations, the addition of the various timelines serve only to generate additional paperwork and administrative burden. **Response:** Requirement R2 ensures notification of those who have a role in identifying Misoperations but were not accounted for within Requirement R1. No change made.
ACES Standards Collaborators	Yes	(1) While we agree the revisions to these requirements clarify what is required, we feel that R2 meets P81 criteria. First, R2 meets P81 criterion A because the requirement of notifying another owner does little to support reliability. Second, R2 meets P81 criterion B1 because it is clearly administrative, and it meets P81 criterion B4 because it requires reporting to another party. Without significant justification for how this administrative, reporting requirement materially and substantially supports reliability, we cannot support it. We suggest that requirement R2 should be removed and an explanation of the desired reporting would be appropriate in the Application Guidelines. The Application Guidelines on page 28 in the first paragraph acknowledges that "notifying the other owners... may unnecessarily burden the other owners with compliance obligations, redirect valuable resources, and add little benefit to reliability." **Response:** Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. No change made. (2) If Requirement R2 persists, we cannot support a medium VRF for R2. This requirement simply does not rise to the level of having an "impact on the electric state or capability of the bulk electric system" which is what is required to meet the Medium VRF criteria. The requirement is an administrative requirement and does not have any impact on the electric state or capability.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team disagrees because a lower Violation Risk Factor (VRF) is a requirement that is administrative in nature and a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system. A planning requirement that is administrative in nature. However, any unresolved Misoperations of jointly owned equipment or operations that are not ruled out as a Misoperation could contribute to the severity of future disturbances affecting a wider area, or potential equipment damage. However, violation of this requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures. Because of this, the drafting team has selected a VRF of Medium. Please refer to the VRF/VSL Justification document. No change made. (3) While we believe that R2 meets P81 criteria and should be removed, if the requirement persists, we recommend removing the Distribution Provider from the applicability section. By definition, the Distribution Provider cannot own a "BES interrupting device" since it is a BES Element as explained on page 21 in the Application Guidelines. The Distribution Provider provides the wires between the BES and the end-use customer. It is the TO/TOP that owns/operates an integrated transmission Element that is 100 kV or higher. This is consistent with statement of registry criteria and the BES definition. If a Distribution Provider does own a BES interrupting device, then they will also be registered as a TO. If they are not, then NERC/regional entity has made a determination per Note 1 in the statement of compliance registry criteria that the BES interrupting device does not have a material impact on the reliability of the bulk electric system and has not registered them. Furthermore, the Application Guidelines state that the BES interrupting device is not part of the Protection System so there is no reason for the requirement to apply to the Distribution Provider.

Organization	Yes or No	Question 2 Comment
		Response: The Distribution Provider (DP) provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage. In this case, the DP may own a non-BES Protection System which operates a BES interrupting device. This rationale supports including the DP as an applicable entity in the proposed standard. Also, BES interrupting device "mechanisms" are not a part of the Protection System as noted in the Application Guidelines; however, the trip coil(s) is a part of the BES interrupting device and Protection System. No change made. (4) Requirement R3 needs to be further clarified for the situation when an entity is not able to identify if a Protection System operation was a correct operation or a Misoperation. This is particularly true for older technology such as electromechanical relays which may lack the necessary information to make such a determination. As the requirement is literally written, it requires the responsible entity "to identify whether its Protection System component(s) caused a Misoperation." If a responsible entity is unable to determine a whether the relay operated as designed, then the requirement would be technically violated. The VSL for R3 results in a severe violation if the responsible entity failed to identify a Protection System Misoperation. There should be some flexibility for instances where the operation is unknown. **Response:** The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team notes the Violation Severity Level of Severe here is for failing to perform the Requirement, not failing to properly identify the operation as a Misoperation. No change made.
ReliabilityFirst Protection Subcommittee	Yes	There was some confusion on who takes lead responsibility for R1 when the associated BES interrupting device has multiple owners (i.e. single breaker that has multiple owners, two breakers associated with a line or generator on a ring bus with a different owner for each breaker, a three-terminal line with different owners for each terminal). Perhaps some additional examples in the Application Guidelines focusing on this situation would be helpful in reducing this confusion. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. A change was made to Requirement R2, 2.1, "notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System" to address this concern. Change made.
SERC Protection and Controls Subcommittee	Yes	1. Recommend that R1.3 be simplified by rewording to indicate that "The BES interrupting device owner identified that its Protection System component(s) caused the Misoperation." **Response:** Although the drafting team understands the reason for the suggestion, it does not meet the intent of the three Parts 1.1 through 1.3. The three Parts are criteria which must be met to determine whether the Protection System operation is a reviewable event by the entity. The Misoperation is determined under the main Requirement R1, if the event meets the three Parts. No change made. A redline of the commenter's proposal above is provided using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: "The

Organization	Yes or No	Question 2 Comment
		BES interrupting device owner identified that its Protection System component(s) caused the Misoperation ~~the BES interrupting device operation~~." 2. The calendar day time keeping requirements create additional burden on entities to track and maintain additional records for each entities timeline dates; especially R3 where the allotted time to identify the Misoperation is dependent on when someone else notifies them. The 60 calendar day time frame is reasonable, but creates potential for non-compliance just because of an arbitrary date. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made. 3. Please add an explanation in the R2 Application Guidelines for situations in which one group investigates for multiple registered entities. It's quite common for a single protective relay engineering group to investigate for the TO, GO, and DP that their company owns. We suggest the following note "(Note: In cases where a single group performs an overall investigation for several entities each with some ownership of the Composite Protection System; a single document (or electronic database) is sufficient to meet the R2 and R3 notification requirements for use by both Registered Entities.)" be added to the Rational boxes for R1, R2 and R3 as well as to the Application Guidelines. This reduces the administrative overhead of having to send yourself an email just to prove that R2 and R3 are met. The important action of identifying and correcting Misoperation causes is still done and duly documented. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made.

Organization	Yes or No	Question 2 Comment
		A change was made to Requirement R2, 2.1, “notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System” to address this concern. Change made. 4. Please augment M2 with ‘databases’ to more clearly allow for a single group investigating on behalf of multiple entities (e.g., GO, TO, DP) to date the notification within their database. For example, CTs on a GO breaker may be part of an adjacent TO switchyard bus protection, so there are two entity owners regarding the Composite Protection System. If owned by the same corporation, one system protection group investigates on behalf of the GO and TO, and act to identify and correct Misoperation causes. **Response:** The drafting team notes that the Measures for the Requirements above include examples of evidence and are not all inclusive. Other forms of evidence may be used at the entity’s discretion. No change made.
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	Yes	ICLP believes that the latest draft of PRC-004-3 corrects a gap where a delayed investigation by one entity could lead to a finding of a violation on the other. Requirements R2 and R3 address this potentially unfair scenario. **Response:** Thank you for your comment and support.
Ameren	Yes	(1) Ameren adopts all the SERC PCS comments by reference. **Response:** Please see the response to the SERC Protection and Controls Subcommittee. (2) A primary reason for our negative ballot on this draft 4 is the proposed clarification (included with SERC PCS comments) to allow a System Protection group of one company’s TO, GO, and DP to document R2 and R3 notifications within its database or PRC-004 software, rather than exchange emails or Faxes.

Organization	Yes or No	Question 2 Comment
		Response: The drafting team notes that the Measures for the Requirements above include examples of evidence and are not all inclusive. Other forms of evidence may be used at the entity's discretion. No change made.
ITC	Yes	ITC Holdings is concerned with the documentation requirements to track communications between the BES interrupting device owner and the protection system owner. An auditor may become more interested in communication dates being more important to them than identifying the cause of the misoperation and implementation of the corrective action plan. **Response:** The drafting team asserts that entities may have varying and multiple communications in their efforts to identify potential Misoperations. Evidence must demonstrate that the BES interrupting device owner communicated to other owner(s) (i.e., Requirement R2). For the notified entity, it would demonstrate receipt of notification from the BES interrupting device owner (i.e., Requirement R3). No change made.
US Bureau of Reclamation	Yes	
JEA	Yes	
Arizona Public Service Company	Yes	
Florida Power & Light	Yes	
Duke Energy	Yes	
Tennessee Valley Authority	Yes	

Organization	Yes or No	Question 2 Comment
SPP Standards Review Group	Yes	
Manitoba Hydro	Yes	
PJM Interconnection	Yes	
Flathead Electric Cooperative, Inc.	Yes	
American Transmission Company	Yes	
LCRA Transmission Services Corp	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Company	Yes	
Nebraska Public Power District	Yes	
Independent Electricity System Operator	Yes	
Kansas City Power & Light	Yes	

Organization	Yes or No	Question 2 Comment
City of Tallahassee	Yes	
City of Tallahassee	Yes	
City of Tallahassee	Yes	
Oncor Electric Delivery Company LLC	Yes	
Public Service Enterprise Group	Yes	
Consumers Energy Company	Yes	
TransÉnergie Hydro-Québec	Yes	
Northeast Utilities	Yes	
Tacoma Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Cowlitz PUD	Yes	
Liberty Electric Power LLC	Yes	

3. **Based on stakeholder input, the drafting team removed the previous Requirement R3 (action plan) and proposed a new Requirement R4 which provides entities time to investigate the Misoperation to determine its cause(s). Do you agree this modification clarified performance and removed ambiguity regarding the action plan? If not, please provide specific suggestions for improvement.**

Summary Consideration: Approximately 52 commenters responded to this question about the replacement of the previous "action plan" with "investigative actions." More than half agreed with the proposed change. The majority of commenters responding "no" to the question had concerns that the standard drafting team (SDT) addressed with either a revision to the standard or a clarification in the Application Guidelines. The following is a summary of the significant issues and whether the concern resulted in a change or not.

There were two significant majority comments. First, two comments supported by approximately 33 individuals identified problems with the Measure(s). The SDT corrected the issue by adding the necessary text. Second, two comments supported by about 26 individuals were concerned about how "investigative actions" would be handled by an auditor or what constituted an investigative action to demonstrate compliance. The SDT provided additional information in the Application Guidelines. There was one minority comment by two individuals that requested clarification about the timeframes used in Requirement R4. The SDT made clarifications in the Application Guidelines to note that timeframes are distinct and separate from the other Requirements.

There were no majority comments in this section, but there were a number of minority comments and too many to summarize in a meaningful way in this summary; detailed responses are provided in response to individual comments, below. The following are the most notable. Approximately six individuals had varying concerns about the auditability of Requirement R4, whether or not it is measurable, that the timeframes are either too constrictive or open-ended, or if the times are separate from other Requirements. The SDT contends the timeframes are reasonable given that investigative actions may take several months to complete between actions. For example, scheduling an outage of a transmission line. The timeframes are distinct. Two commenters believe the Requirement R4 should require the entities to determine the cause rather than indirectly assuming the cause would be found in Requirements R1 or R3 which focus on Misoperation identification. Another commenter requested a provision for extenuating circumstances which is better handled through the enforcement space according to the NERC Rules of Procedure.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	We agree with the requirements as revised, but do not agree with the Measures. Measures: The performance target is that the responsible entity performed investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, and the identification of the cause(s) of the Misoperation or a declaration that no cause was identified. **Response:** The Measures have been updated. Change made. The term “investigative action(s)” is ambiguous even given the example cited in the Application Guidelines. Since this is an auditable measure, this term should be defined in the standard. **Response:** The Application Guidelines has been updated to provide additional guidance on the expectation of investigative actions under the section heading “Requirement R4.” Change made.
MRO NERC Standards Review Forum	No	The NSRF believe that there are many potential forms of “owners” and that “owners” needs to be modified to read, “other NERC registered applicable entities” to avoid a paragraph 81 administrative issue that has no bearing on reliability. Exclusions must be identified in R1, R2, R3, and R4 for joint protection system owners that actually don’t have any impact on the operation of the protection systems. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. A change was made to Requirement R2, 2.1, “notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System” to address this concern. Change made.

Organization	Yes or No	Question 3 Comment
FirstEnergy Corp	No	Does NERC intend to be prescriptive with respect to a template for a Corrective Action Plan, or will the Regional Entities accept whatever format and tracking documentation is provided by the Registered Entities, even though they may be varied among the Entities? **Response:** There is nothing prescriptive in the Requirements concerning a Corrective Action Plan. The entity may use its discretion to determine how to create it. By definition, a CAP contains actions and a timetable to remedy a specific problem. No change made. The measures identified in M6 seem as though they could be subject to interpretation by an Auditor. **Response:** The Measures have been updated. Change made.
PPL NERC Registered Affiliates	No	The expression, "or that decided a Misoperation cannot be ruled-out," should be added in R4 after, "has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3," per the rationale in our comment above for R1. The outcomes listed under R4 should be expanded as shown below; since, if there are Misoperations for which no cause can ever be identified, there can also be possible-Misoperations for which a yes-or-no determination can never be made. • The identification of the cause(s) of the Misoperation; or • A declaration that no cause of the Misoperation was identified; or • A declaration for an event for which a Misoperation cannot be ruled-out that no Misoperation can be proven. **Response:** The 120 calendar days is to determine whether or not a Misoperation occurred. The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the

Organization	Yes or No	Question 3 Comment
		continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause of the Misoperation was identified; or • **A declaration for an event for which a Misoperation cannot be ruled-out that no Misoperation can be proven**.
Tennessee Valley Authority	No	Currently, there is not a clear indication of regulatory relief for an entity following a major natural disaster. When recovering from major events such as Hurricane Sandy, the first priority is to get lights on and rebuild the system. Because a large natural event produces an influx of unique system configurations that may not have been planned for by system planners or relay setters, analyzing and investigating all the operations and misoperations that occur takes months and is not the top priority for a utility that endures such an event. We respectfully request that the standard drafting committee add wording to allow additional time when a utility endures a natural disaster. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (time frames) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.

Organization	Yes or No	Question 3 Comment
ACES Standards Collaborators	No	(1) This requirement should be modified to simply state that the applicable entity is required to identify the cause of the Misoperation or document that a cause could not be found. It is too prescriptive that an applicable entity must identify investigative actions each successive two calendar quarters. This makes the requirement inflexible and needs to be simplified. Consider an example where an applicable entity that should be performing more investigative actions every two successive calendar quarters can be compliant by simply identifying one and an applicable entity in a unique situation that cannot perform even a single investigative action in the two successive calendar quarters due to extenuating circumstances would be in technical non-compliance. **Response:** The drafting team asserts that Requirement R4 mandates the applicable entity to exercise due diligence to pursue the cause of the Misoperation until the cause is found or document that a cause could not be found. Requirement R4 is structured in such a way to ensure identified Misoperations with no cause are either investigated to identify the cause or that a declaration is made to close the investigative action(s) if no cause is identified. In addition, a requirement needs to be auditable and measureable. No change made. (2) This requirement incorrectly implies that R1 and R3 require the applicable entity to identify the cause of the Misoperation. They do not. Rather, R1 and R3 simply require the applicable entity to identify Misoperations. Thus, R4 should be modified to simply require identification of the cause of the Misoperation subject to reasonable investigative actives or declaration that the cause could not be identified after completing reasonable investigative actions. **Response:** Requirement R4 is not applicable if the “cause” of the Misoperation is known. The “cause” may be found when performing Requirements R1 and R3. If not, Requirement R4 requires the entity to perform at least one investigative action every two calendar quarters following the identification of a Misoperation or make a declaration. No change made.

Organization	Yes or No	Question 3 Comment
ReliabilityFirst Protection Subcommittee	No	The direction included in R4 is awkwardly worded. Consider rewording the following "shall perform investigative action(s)... at least once every two full calendar quarters" AS "shall, on a semi-annual basis, continue to show evidence of investigation...". However, the examples in the Application Guidelines are clear as to what the SDT is looking for. **Response:** The drafting team appreciates the suggestion and has decided to leave the Requirement as written. No change made.
ReliabilityFirst	No	ReliabilityFirst has a number of concerns with Requirement R4. First, from compliance/enforcement perspective, Requirement R4 is not sufficiently distinct from Requirements R1 and R3 (it creates a "double jeopardy situation"). For example, Requirement R3 requires the responsible entity to "...identify whether its Protection System component(s) caused a Misoperation". As written, if the responsible entity fails to "...identify whether its Protection System component(s) caused a Misoperation" this could be grounds for a possible violation of Requirement R3. This is evident in the associated Violation Severity Levels where failing "...to identify whether or not a Misoperation its Protection System component(s) occurred" is a Severe Violation. This is in direct conflict with Requirement R4, which gives the responsible entity additional time to perform investigation actions to determine the cause of the Misoperation. ReliabilityFirst agrees with the intent of what Requirement R4 is trying to accomplish but from a compliance/enforcement standpoint it will cause issues. **Response:** Requirements R1 and R3 are for determining whether a Misoperation occurred or not. Requirement R4 is for determining the cause(s), if not determined while performing Requirements R1 or R3. Requirement R4 has been clarified. Change made. Second, as already noted, ReliabilityFirst agrees with the intent of what Requirement R4 is trying to accomplish, but notes that there is no ending time period associated with how long the responsible entity has to complete the investigation. As written, a responsible entity can hypothetically drag out the investigations and never officially complete the investigation.

Organization	Yes or No	Question 3 Comment
		ReliabilityFirst believes in order to close the loop, the responsible entity should be limited to four calendar quarters to complete the investigation (i.e., either identification of the cause(s) of the Misoperation or declaration that no cause can be identified). To address the two concerns, ReliabilityFirst recommends including similar language as noted in Requirement R4 as sub parts in Requirement R1 and R3 along with including an ending completion timeframe as well. The following is an example for consideration for Requirement R3: R3. Each Transmission Owner, Generator Owner, and Distribution Provider that receives notification, pursuant to Requirement R2, within the later of 60 calendar days of notification or 120 calendar days of the BES interrupting device(s) operation, shall identify whether its Protection System component(s) caused a Misoperation. If the cause(s) of the Misoperation cannot be determined, the Transmission Owner, Generator Owner, and Distribution Provider shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters, but for no more than four calendar quarters after the Misoperation was first identified, until one of the following actions completes the investigation: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified. **Response:** The drafting team asserts that Requirement R4 is intended to allow the entity the time needed for identifying the cause(s) of a Misoperation. Shortening the period would have the unintended consequence of having entities prematurely declaring that the cause was not found. It is up to each entity to determine how long it wants to continue its investigative work to determine the cause(s) of a Misoperation. No change made.
Manitoba Hydro	No	(1) For R4, Manitoba Hydro does not think that there is a need to perform investigative actions to determine the cause of the Misoperation at least once every two full quarters.

Organization	Yes or No	Question 3 Comment
		Repeated investigative actions would not be productive in identifying the cause. We propose this requirement to read as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation, until one of the following is completed: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified." **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: "Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation ~~at least once every two full calendar quarters after the Misoperation was first identified~~, until one of the following ~~completes the investigation~~ is completed: • The identification of the cause(s) of the Misoperation; or • A declaration that no cause was identified."
Muscatine Power and Water	No	MP&W believes that there are many potential forms of "owners" and that "owners" needs to be modified to read, "other NERC registered applicable entities" to avoid a paragraph 81 administrative issue that has no bearing on reliability. Exclusions must be identified in R1,

Organization	Yes or No	Question 3 Comment
		R2, R3, and R4 for joint protection system owners that actually don't have any impact on the operation of the protection systems. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. A change was made to Requirement R2, 2.1, "notification of the operation shall be provided to the other owner(s) that share Misoperation identification responsibility for the Composite Protection System" to address this concern. Change made.
American Transmission Company	No	ATC's experience has been that the cause of a Misoperation is determined within the first couple months following its occurrence. If the cause is not found in that time, it is unlikely to be found. Relative to R4, the parameters around investigative actions are not very productive, as revisiting the same information after an extended period of time does not typically lead to determining a cause. **Response:** The drafting team agrees that most Misoperation cause(s) are determined in the first phase of review and afterward the likelihood of determine the cause diminishes; however, Requirement R4 allows the entity a mechanism to continue the investigation without being out of compliance with Requirements R1 or R3 as the case may be. The drafting team understands that entities may need to schedule additional investigation (i.e., activities) such as taking an outage or sending equipment off to manufactures for testing and inspection. Requirement R4 provides this avenue to promote determining the cause(s) of Misoperations. No change made. ATC recommends removing the language in R4 that speaks to investigative steps "at least once every two full calendar quarters after the Misoperation was first identified."

Organization	Yes or No	Question 3 Comment
		Response: The drafting team originally discussed not having a time period associated with Requirement R4; however, in considering that approach, it was determined that the Requirement would not be measurable or auditable. No change made.
Exelon	No	How soon after a misoperation can a declaration of no cause be submitted? **Response:** The drafting team notes there is no prescribed time period. An entity should reasonably exhaust its efforts to determine the cause(s) of a Misoperation. The Application Guidelines under the heading "Requirement R4" provides additional direction regarding this comment. No change made. Exelon agrees that a prompt investigation of the event should occur and prudent corrective action be initiated as detailed in the new Requirement R4; however, if the Standard is allowing a provision for continued investigations then the other requirements in the Standard should align. Requirement R4 needs to be modified or R1 needs to be modified to align with each other. The current wording in R4 provides a requirement that cannot be met unless the entity is not in compliance with R1. R3 provides the wording such as "cannot rule out" and "or cannot determine". This wording needs to also be added to R1 for completeness. In addition, the wording in the VRFs and VSLs needs to be adjusted to accommodate those events where the cause of the interrupting device operation has not yet been determined. **Response:** Requirement R4 is not applicable if the "cause" of the Misoperation is known. The "cause" may be found when performing Requirements R1 and R3. If not, Requirement R4 requires the entity to perform at least one investigative action every two calendar quarters following the identification of a Misoperation or make a declaration. No change made.
Kansas City Power & Light	No	The inclusion of the following phrase is ambiguous. "..... shall perform investigative actions to determine the cause of the misoperation at least once every two full calendar quarters

Organization	Yes or No	Question 3 Comment
		after the misoperation was first identified, until one of the following completes the investigation: • The identification of the cause of the misoperation; or • A declaration that no cause was identified." I would remove "at least once every two full calendar quarters after the misoperation was first identified." If the drafting team wants to set a time limit on the investigation, then state a not-to-exceed time period. **Response:** The drafting team originally discussed not having a time period associated with Requirement R4; however, in considering that approach, it was determined that the Requirement would not be measurable or auditable. No change made. A declaration should be available once an entity has completed all of its diagnostic tests, even if the declaration comes in the first calendar quarter after the misoperation. During the NERC webinar, one of the drafting team members indicated that the declaration could be made at any time, but I can envision a Compliance Enforcement Authority reading the language of R4 and asking why you didn't fulfill the requirement to test in the second full calendar quarter. **Response:** The drafting team notes there is no prescribed time period. An entity should reasonably exhaust its efforts to determine the cause(s) of a Misoperation. The Application Guidelines under the heading "Requirement R4" provides additional direction regarding this comment. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard.

Organization	Yes or No	Question 3 Comment
		Response: Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
Public Service Enterprise Group	No	In R4, we find the phrase “two calendar quarters” unclear since it is referenced from the date when the Misoperation was identified. For simplicity, that phrase should be replaced with “180 days.” Also, there may be a need to extend the time. For example, if an investigation required removing a transmission line from service, one may not be able to obtain a clearance to do so within 180 days, so an investigation action could not be performed, resulting is a violation of R4. Therefore, the 180 day time frame should be allowed to be extended for good cause if the owner documents the cause of an extension. Our recommendation is to replace R4 with this language:

Organization	Yes or No	Question 3 Comment
		"Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every 180 days after the Misoperation was first identified (which 180 days may be extended by the Transmission Owner, Generation Owner, or Distribution Provider for a documented good cause), until one of the following completes the investigation:" **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: "Each Transmission Owner, Generator Owner, and Distribution Provider that has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 or R3 shall perform investigative action(s) to determine the cause of the Misoperation at least once every ~~**two full calendar quarters after the Misoperation was first identified**~~ **180 days after the Misoperation was first identified (which 180 days may be extended by the Transmission Owner, Generation Owner, or Distribution Provider for a documented good cause),** until one of the following completes the investigation:" Finally, in the "Rationale" text box, the phrase "(120 calendar days)" should be stricken since it does not apply to R3. If notice per R2 is given on day 120, the entity under R3 has 60 day time period, while if notice is given on day 1, it has a 119 day time period. **Response:** The drafting team believes the reference above is in error. The "(120 calendar day)" reference is in the rationale box for Requirement R4 to highlight that Requirements R1 and R3 are distinct and separate from the time period in Requirement R4. No change made.

Organization	Yes or No	Question 3 Comment
Northeast Utilities	No	The term "investigative action(s)" used in Requirement 4 is somewhat ambiguous even given the examples cited in the Application Guidelines. Since this is an auditable measure, this term should be defined in the standard. Can simply confirming an outage schedule be enough of an investigative action to satisfy all compliance auditors as suggested in the Application Guidelines? **Response:** The Application Guidelines has been updated to provide additional guidance on the expectation of investigative actions under the section heading "Requirement R4." Change made.
Texas Reliability Entity	No	There should be an end time frame for this requirement. If an entity has not determined if a Misoperation occurred within 120 days of the interrupting device operation, they could conceivably continue to investigate the event for years, as long as they perform an investigative action at least once every 6 months. **Response:** The drafting team asserts that Requirement R4 mandates the applicable entity to exercise due diligence to pursue the cause of the Misoperation until the cause is found or document that a cause could not be found. Requirement R4 is structured in such a way to ensure identified Misoperations with no cause are either investigated to identify the cause or that a declaration is made to close the investigative action(s) if no cause is identified. In addition, a requirement needs to be auditable and measureable. The Application Guidelines under the heading "Requirement R4" provides direction regarding this question. No change made.
CenterPoint Energy Houston Electric LLC	No	CenterPoint Energy believes a requirement to perform investigative actions to determine the cause of a Misoperation at least once every two full calendar quarters after the Misoperation was first identified will result in repetitious investigative actions and scheduled outages and would provide little benefit.

Organization	Yes or No	Question 3 Comment
		Response: The drafting team notes there is no prescribed time period. An entity should reasonably exhaust its efforts to determine the cause(s) of a Misoperation. The Application Guidelines under the heading “Requirement R4” provides additional direction regarding this comment. No change made. Also, we do not believe a declaration is needed, since assigning a cause code of Unknown / Unexplainable is part of the misoperation analysis process. The Cause Code and an explanation of the exhaustive investigation and tests conducted should be sufficient. Therefore, we recommend Requirement R4 be deleted. **Response:** The declaration in Requirement R4 is meant to be distinct and separate from the reporting aspects under the NERC Rules of Procedure, Section 1600, Request for Information or Data for compliance purposes. No change made.
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	On page 28 of the clean draft #4, in the first sentence of the R4 section, the words "the entity" appearing after the comma are redundant and are not needed. **Response:** The drafting team agrees and has removed the additional “the entity” from the sentence. Change made.

Organization	Yes or No	Question 3 Comment
Virginia State Corporation Commisison	Yes	I have one wording suggestion for R3. I suggest moving the words "shall identify" from their present location to follow immediately after "Requirement R2." The sentence would then read "Each TO, GO and Distribution Provider that receives notification pursuant to Requirement R2, shall identify within the later of 60 days.....device(s) operation, whether its Protection System component(s) caused a Misoperation." **Response:** The drafting team appreciates the suggestion and has decided to leave the Requirement as written. No change made.
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	Yes	ICLP appreciates the precise language used in Requirement R4 - which allows sufficient time to investigate a Misoperation, while limiting it to within reasonable bounds. We agree that if a cause cannot be found through good faith investigation within two calendar quarters, there is little benefit to pursuing the case further. **Response:** The drafting team appreciates the comment and support.
American Electric Power	Yes	AEP recommends replacing "at least once every two full calendar quarters after the Misoperation was first identified" with "at least once every six month period after the Misoperation was first identified". **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Puget Sound Energy	Yes	
US Bureau of Reclamation	Yes	

Organization	Yes or No	Question 3 Comment
JEA	Yes	
Arizona Public Service Company	Yes	
Florida Power & Light	Yes	
Duke Energy	Yes	
Dominion	Yes	
SPP Standards Review Group	Yes	
SERC Protection and Controls Subcommittee	Yes	
Wisconsin Electric Power Company	Yes	
PJM Interconnection	Yes	
LCRA Transmission Services Corp	Yes	
Entergy Services, Inc.	Yes	
Idaho Power Company	Yes	

Organization	Yes or No	Question 3 Comment
Nebraska Public Power District	Yes	
Independent Electricity System Operator	Yes	
Oncor Electric Delivery Company LLC	Yes	
Ameren	Yes	
Consumers Energy Company	Yes	
TransÉnergie Hydro-Québec	Yes	
Tacoma Power	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Xcel Energy	Yes	
Hydro-Québec Production	Yes	

Organization	Yes or No	Question 3 Comment
Tri-State Generation and Transmission Association, Inc.	Yes	
Cowlitz PUD	Yes	
ITC	Yes	
Liberty Electric Power LLC	Yes	

4. **The drafting team modified the Application Guidelines to improve examples and clarify the team's intent on various topics. Do you agree the Application Guidelines provide sufficient examples and clarity? If not, please provide specific suggestions for improvement.**

Summary Consideration: Approximately 50 commenters responded to this question about the overall comprehensiveness of the Application Guidelines. Commenters were equally divided as to whether the Application Guidelines were sufficient. The majority of commenters responding "no" to the question had concerns that the SDT addressed with either a revision to the standard or a clarification in the Application Guidelines. The following is a summary of the significant issues and whether the concern resulted in a change or not.

The following is a summary of the comments that resulted in a change. There were four majority comment themes. First, approximately six comments represented by 24 individuals requested additional specificity concerning the definition of "Misoperation" with regard to categories 3 and 4 ("Slow Trip"). The SDT made several changes to the Application Guidelines in addition to revisions to the definition. Second, about seven comments supported by 13 individuals requested clarifications concerning equipment. The SDT made clarifications to the Application Guidelines in reference to sync check relays, breaker failure, reverse power relays, control functions, and mechanical parts of breakers. Third, approximately four comments supported by ten individuals requested clarity regarding who had responsibility for the Corrective Action Plan (CAP), the extent of the evaluation of other Protection Systems, and/or the reporting of Misoperations. The SDT provided clarifications in the Application Guidelines except for reporting which will be handled through the NERC Rules of Procedure, Section 1600, Request for Data or Information. The last majority comments requested various clarifications or examples for the definition of "Composite Protection System." The SDT provided additional narratives and examples for various BES Elements (e.g., transformer, generator, and transmission line). Other additions included improving discussion concerning investigative actions and the definition of "Misoperation" to include on-site personnel.

There were three notable minority comments which resulted in a change. One comment supported by 11 individuals was stating uncertainty whether to identify an operation as a "Misoperation" if unsure or to consider the operation "correct." The SDT provided additional clarification in the Application Guidelines on the approaches an entity could take to continue its investigation. Two comments from individuals requested clarification on how to handle multiple automatic recloses of a BES interrupting device by a Protection System. The SDT provided clarification based on existing NERC System Protection and Control Subcommittee guidance. Last, one commenter requested an exclusion of Remedial Action Schemes (RAS) and Special Protection Systems (SPS). The SDT provided an exclusion in the Applicability section of the standard to make clear this perceived sub-set of a Protection System is not applicable to the standard.

There were two majority comments which did not result in a change to the standard. First, there were approximately five comments supported by 22 individuals that were either concerned the Regional Entities would no longer review CAPs or wanted to know more about the reporting of Misoperations. The SDT provided feedback below in the responses and directed commenters to the data request concerning the reporting of Misoperations. Second, about five comments supported by 11 individuals raised questions as to whether a certain scenarios were a Misoperation. Some scenarios could be determined whether they were Misoperations or not by the information provided by the commenter, others could not. Most notable minority comments which did not result in a change include: a request to add undervoltage load shedding (UVLS), a provision for extenuating circumstances, and a requirement to share information between different owners of Protection Systems. The SDT noted that UVLS would be handled after industry approval, extenuating circumstances are best handled in the enforcement space according to the NERC Rules of Procedure, and the request to share information requirement would not have a reliability benefit.

Organization	Yes or No	Question 4 Comment
Puget Sound Energy	No	a) Application Guidelines could have more specificity, in addition to examples. For example, in #4 (Slow Trip - Other than Fault), it should be spelled out that each possible Misoperation should be studied to test for possible effects on system stability. Other specific expectations, if any, should also be spelled out. **Response:** The drafting team has modified the Slow Trip portion of the definition of "Misoperation" to address this concern. Change made. b) In addition, "Other than Fault" should be clarified and explained together with the definition of SPS/RAS, which are excluded from PRC-004. (SPS/RAS are defined as non fault protection schemes). **Response:** The drafting team contends that "Other than Fault" does not need further clarification.

Organization	Yes or No	Question 4 Comment
		Response: Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). An exclusion for RAS/SPS has been added to the Applicability section. Change made. c) UFLS/UVLS should always be mentioned together in PRC-004-3 (unless both are not included). **Response:** Currently, underfrequency load shedding (UFLS) is applicable to the proposed standard to close a gap in reliability. No change made. Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. d) Should sync check and breaker failure be considered in the Application Guidelines - what category do these fall into? **Response:** Sync check is not included as a part of a Protection System and is not within scope of the proposed standard. Breaker failure has been clarified in the Application Guidelines. Change made. e) In all six parts of the Misoperation Definition, the phrase "...where tripping for protection purposes is involved" could be included for clarity. **Response:** The drafting team has modified the definition of "Misoperation" to address this concern. Change made.
US Bureau of Reclamation	No	Reclamation suggests that the drafting team update the Application Guidelines to provide an example of a Composite Protection System for a generator, a transformer, and a

Organization	Yes or No	Question 4 Comment
		transmission line so that industry will have guidance on the scope of typical Composite Protection Systems. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
FirstEnergy Corp	No	None of the Requirements address notifying the Regional Entity on a periodic basis, as is done now (quarterly for RFC). Is it going to be up to the Regional Entity to identify: a. Whether periodic data submittals will be required? b. If so, the periodicity and the template / format for those data submittals? **Response:** The drafting team does not anticipate that Regions actively involved with Protection System operation reviews to end these activities. The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[3] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made.
PPL NERC Registered Affiliates	No	PPL NERC Registered Affiliates comments above for the Slow Trip portion of the Applications Guidelines. A statement should be added, “A Misoperation should not be assumed when the cause of a relay operation cannot be authoritatively established,” (reference response to question #3) **Response:** The intent of the definition of “Misoperation” and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The

[3] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Organization	Yes or No	Question 4 Comment
		standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. The discussion of reverse power relays on pg. 26 would be clearer if it included some of the topics and points made in the 2/20/2014 Protection Systems Misoperations Webinar. We propose stating that "The control-vs.-protective demarcation of reverse power relays is based on the operation at hand and not programming". Failure of a reverse power relay to open the breaker at the established time after commencement of motoring is not a Misoperation if using the relay to trip a unit as part of a normal stop sequence. The same failure would be a Misoperation if some unintended event caused the unit to import power. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. The statement on pg. 27, "The entity is allotted 120 calendar days from the date of its BES interrupting device operation to identify whether or not a Misoperation of its Protection System component(s) occurred," should be amended per our comments above for R4. That is, NERC has stated in R4 that determining the cause of a relay operation may take a very long time, and a Misoperation yes-or-no decision may not be possible if the cause for the trip is not known. **Response:** The 120 calendar days is to determine whether or not a Misoperation occurred. The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be

Organization	Yes or No	Question 4 Comment
		found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. Correction is also needed for the flowchart on pg. 35. “A known or possible Misoperation,” should be substituted for, “the Misoperation,” at the top of pg. 29, and elsewhere that this expression is used, because undetermined cause for tripping can make a Misoperation yes-or-no decision impossible. **Response:** The intent of the definition of “Misoperation” and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. The outcome of Requirement R1 or R3 has to be a determination of whether or not a Misoperation occurred. The suggested phrase does not provide additional clarity. Also, the flowchart is intended to provide entities guidance in the relationship between the Requirements within the proposed standard. No change made. The statement on p.29, “certain planned investigative actions may require months to schedule and complete,” should be changed to, “certain planned investigative actions may require months or even years to schedule and complete,” in recognition that generation units are intended to operate for years between planned outages and frequently must be returned to service as soon as possible in the event of a forced outage. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. A redline of the commenter’s proposal above is provided below using **blue with underline** for additions and ~~red with strikethrough~~ for deletions to illustrate the requested revision:

Organization	Yes or No	Question 4 Comment
		"certain planned investigative actions may require months **or even years** to schedule and complete," The following statement should be added at the end of the same paragraph, "Taking equipment out of service for the sake of furthering the investigation is not required, and forced outages need not be prolonged for troubleshooting. However, planned outages should include any testing or other actions for which downtime is necessary." The discussion on pg. 30 should include the point that a CAP must be developed within 60 days, but implementing the CAP may take much longer if requiring a downtime opportunity. An example should be included for multiple CAPs under the circumstance of extended troubleshooting, (e.g. taking action for the apparent cause of a Misoperation), developing a new theory and taking different action when the event occurs again several months later and making a final and successful corrective action when the problem occurs a third time. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Dominion	No	a). During the webinar there were a number of questions about reverse power protection when used as protection or used as control. This indicates that there is still confusion with current examples given in the Guidelines. Recommend expanding examples to include: 1. A gas turbine generator has a single reverse power relay which is used to trip the generator breaker during a normal controlled shutdown. This function is considered a control function and not counted as an operation or a Misoperation. 2. The reverse power relay (mentioned in example 1) does not operate to trip the generator breaker and the unit continues to motor until the operator intervenes and opens the

Organization	Yes or No	Question 4 Comment
		breaker manually. Is this a Misoperation? If so what protection system misoperated? Is this considered a Misoperation due to lack of protection? 3. The gas turbine generator mentioned in example 1 and 2 also has a separate reverse power relay that directly trips the generator lockout relay. Is this function considered part of the Protection System? With the unit operating at normal load, this relay incorrectly trips the unit due to an internal relay problem. Is this a Misoperation? 4. A steam turbine generator has a reverse power relay (sometimes referred to as a Sequential trip relay) used in conjunction with valve position switches to trip the generator following a turbine trip. This function is considered a control function and not counted as an operation or a Misoperation. 5. The reverse power relay mentioned in example 4 (sometimes referred to as an Anti-motoring relay) does not operate during a turbine trip and after thirty seconds a second reverse power relay operates as designed to directly trip the generator lockout. Is this second reverse power relay considered part of the Protection System? If so is this counted as one operation that needs to be evaluated? **Response:** The drafting team provided clarification in the Application Guidelines under the section “Control Functions.” Change made. b). Mechanical type breaker trip examples should be expanded to show that air pressure, gas pressure and pole disagreement trips (and their associated auxiliary relays) are control functions and therefore not part of the protection System and thus not subject to this standard. In addition, gas and oil type fault pressure relays on transformers are excluded from Protection System. The example should clarify whether the transformer auxiliary tripping relays (sometimes referred to as 63X relays) are part of the Protection System. Examples could be extremely helpful here since no examples are included in the definition of Protection System.

Organization	Yes or No	Question 4 Comment
		Response: The definition of "Protection System" does not include these types of equipment. No change made. c). Additional Application Guideline examples are needed and the following are specific examples that should be considered: 1. A generating unit GSU transformer trips when the unit is off line (lowside gen breaker was open) due to a Misoperation of the generation Protection System owned by the G.O. The switchyard generator breaker trips but is owned by the T.O. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? **Response:** The drafting team does not have sufficient information about the TO's breaker tripping to provide a response. 2. A generating unit trips out immediately upon synchronizing to the grid due to a Misoperation of its Startup Overcurrent protection. The T.O. owns the 230KV generator breaker that was closed and tripped. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify if the G.O. is responsible to identify the cause of the Misoperation and **who is responsible for CAP**, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. 3. A 230-115 KV network transformer trips out when being re-energized following maintenance due to a Misoperation of the transformer differential relay. The operation trips only the highside breaker that was closed to energize the transformer (transformer was not feeding the grid at the time). Application Guidelines should be added to clarify if this is a

Organization	Yes or No	Question 4 Comment
		Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? **Response:** The drafting team has modified the definition of "Misoperation" to address this concern. Change made. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made. 4. A 230 KV shunt capacitor bank trips out when being placed in service due to a Misoperation of the capacitor bank differential relay. The operation trips only the capacitor bank breaker that was closed to energize the bank. Application examples should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? **Response:** The drafting team has modified the definition of "Misoperation" to address this concern. Change made. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made. 5. A 230KV line trips at one terminal via its carrier ground relay during closing of a line switch to re-network the line. There was no fault, but the relay operated during typical phase current imbalance created by the poles of the switch closing at different times. Is this a Misoperation? **Response:** This is not a Misoperation based on the information above that the Protection System sensed the prescribed current imbalance and operated correctly. No change made.
Florida Municipal Power Agency	No	FMPA believes it would be beneficial to actually lay out specific failures in the examples. For example, "Slow Trip - During Fault" simply says "A failure of a line's Composite Protection System to operate as quickly as intended for a line fault is a Misoperation." This is more or

Organization	Yes or No	Question 4 Comment
		less a restatement of the definition but applied with the additional detail of a specific protected component (the transmission line). Rather, consideration should be paid to an actual way a relay could fail - for example“...a line to line fault in a weak portion of the system resulted in positive sequence currents below the overcurrent supervision pickup for a line current differential relay. The relay’s negative sequence differential element operated instead. However, the original relay settings did not account for the additional detection time required for the negative sequence element...” most of the nuance in the application comes from the way the relay failed. Another example might be a line fault with electromechanical relays wherein the relay output contacts stuck initially, resulting in a delayed clear. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
SPP Standards Review Group	No	Our preference would be that during a condition of a high number of outages, such as a hurricane or ice storm, we be allowed to request a formal "state of extenuating circumstances" and extend our deadline from 120 days to 270 days. We object to the proposed process where extenuating circumstances can force a utility into a violation and then rely on a nebulous, subjective review to determine whether penalties will be imposed. **Response:** It appears that the comment is objecting to the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, which have been in place for some time. No change made See additional comments on the Applications Guides contained in Question 5 below.
SERC Protection and Controls Subcommittee	No	See #3 in question 2 above.

Organization	Yes or No	Question 4 Comment
		The examples in the Application Guidelines are beneficial, the SERC PCS suggests it would be beneficial to add additional examples and add clarity to who is to report the Misoperation. Some examples are added below. **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[4] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made. During the recent webinar there were a number of questions about reverse power protection when used as protection or used as control. This indicates that there is still confusion with current examples given in the Guidelines. Recommend expanding examples specific to reverse power. **Response:** The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made. Also, trips should be expanded to show that air or gas system breaker trips or pole disagreement trips are not reportable operations. **Response:** Mechanical systems of a breaker are not included in the definition of "Protection System". No change made. Additional examples are needed and the following are recommended: 1. A generating unit GSU transformer trips when the unit is off line (lowside gen breaker was open) due to a Misoperation of the generation Protection System owned by the G.O. The switchyard generator breaker trips but is owned by the T.O. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the

[4] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Organization	Yes or No	Question 4 Comment
		G.O., identify who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? **Response:** The drafting team does not have sufficient information about the TO's breaker tripping to provide a response. 2. A generating unit trips out immediately upon synchronizing to the grid due to a Misoperation of it's Startup Overcurrent protection. The T.O. owns the 230KV generator breaker that was closed and tripped. Application Guidelines examples should be added to show if this is an operation where the T.O should notify the G.O., identify if the G.O. is responsible to identify the cause of the Misoperation and who is responsible for CAP, clarify is this a reportable generation Misoperation and who should report, T.O. or G.O.? **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made. 3. A 230-115 KV network transformer trips out when being re-energized following maintenance due to a Misoperation of the transformer differential relay. The operation trips only the high-side breaker that was closed to energize the transformer (transformer was not feeding the grid at the time). Application Guidelines should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? **Response:** There is not sufficient information to provide an accurate response. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made. 4. A 230 KV shunt capacitor bank trips out when being placed in service due to a Misoperation of the capacitor bank differential relay. The operation trips only the capacitor

Organization	Yes or No	Question 4 Comment
		bank breaker that was closed to energize the bank. Application examples should be added to clarify if this is a Misoperation and if this a reportable transmission Protection System Misoperation per the current or proposed reporting guidelines? **Response:** Yes, this is a Misoperation. An example has been added to the Application Guidelines. Change made. Identified Misoperations are proposed to be reported under the NERC Rules of Procedure, Section 1600, Request for Data or Information. No change made.
Wisconsin Electric Power Company	No	The examples 8a and 8b under Control Functions should be clarified to help entities make proper distinctions between control functions and protective functions of reverse power relays. We suggest the wording in the paragraph following Example 8b be revised as follows: **Current wording:** In the example above, the standard is not applicable; however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection. For example, reverse power relays are typically installed as the primary protection for a generating unit to guard against motoring. Though, operators often take advantage of this functionality and use the Protection System's reverse power protective function as a normal procedure to shutdown a generating unit. **Suggested wording:** In the examples above, the standard is not applicable because the reverse power elements are performing control functions only. Reverse power relay elements are typically installed as part of the generator Protection System to protect turbine-generators from motoring. Entities often take advantage of this functionality and use the Protection System's reverse power function as a part of a normal procedure to shutdown a generating unit. However, the standard is applicable when the reverse power relaying provides the anti-motoring protective function for the generating unit. For

Organization	Yes or No	Question 4 Comment
		example, if unintended motoring occurs, the reverse power relaying is designed to protect the turbine by tripping the unit. **Response:** The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made. A redline of the commenter's proposal above is provided below using **blue with underline** for additions and ~~**red with strikethrough**~~ for deletions to illustrate the requested revision: **Suggested wording:** In the examples above, the standard is not applicable ~~**however, the standard remains applicable to**~~ because the reverse power elements are performing control functions only. Reverse power relay elements are typically installed as part of the generator Protection System ~~**when intended to provide generator anti-motoring protection. For example, reverse power relays are typically installed as the primary protection for a generating unit to guard against motoring. Though, operator**~~ **to protect turbine-generators from motoring. Entities** often take advantage of this functionality and use the Protection System's reverse power ~~**protective**~~ function as a part of a normal procedure to shutdown a generating unit. **However, the standard is applicable when the reverse power relaying provides the anti-motoring protective function for the generating unit. For example, if unintended motoring occurs, the reverse power relaying is designed to protect the turbine by tripping the unit**.
Flathead Electric Cooperative, Inc.	No	I do not believe that UFLS equipment should be included under this standard. **Response:** Currently, underfrequency load shedding (UFLS) is applicable to the proposed standard to close a gap in reliability. No change made.

Organization	Yes or No	Question 4 Comment
LCRA Transmission Services Corp	No	LCRA TSC recommends the SDT address the topic of temporal aggregation within the Application Guidelines. For example, if a transmission line over-trips for an out-of-section fault three times in a 2-hour interval, perhaps due to persistent storm activity before a relay setting adjustment can be made, does this count as three misoperations, or can the three events of a similar nature and cause be “collapsed” into a single misoperation? Some guidance in this area would be helpful in order to allow entities to be consistent in reporting. LCRA TSC recommends some way to collapse/combine misoperation events of a similar nature within a short, defined timeframe. **Response:** The Application Guidelines have been updated to clarify this situation. Change made. The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template. No change made.
American Electric Power	No	1) AEP recommends adding an example to the applications guideline to illustrate whether repeated operations/misoperations which occur during the same automatic reclosing sequence need a separate identification under R1. **Response:** The Application Guidelines have been updated to clarify this situation. Change made. 2) AEP recommends adding an example to the applications guideline to illustrate that a properly coordinated breaker failure operation does not equate to a “slow trip” type misoperation. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.

Organization	Yes or No	Question 4 Comment
		3) AEP recommends adding an example to illustrate how breaker failure fits into composite protection system. **Response:** Breaker failure has been clarified in the Application Guidelines under the heading, "Definitions." Change made. 4) AEP recommends adding an example where a misoperation is initially identified, but subsequent investigation (after 120 days) reveals a misoperation did not occur. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Nebraska Public Power District	No	The application guidelines state: "The CAP is complete when all the documented actions to resolve the specific problem (i.e., Misoperation) are completed which may include those actions resulting from the entity's evaluation of other locations, if not addressed through a separate CAP." In the example R6b it appears the CAP is completed and a program was established for corrections at other locations. Please clarify if a program to address other locations is or is not required to be tracked as part of PRC-004 evidence. In the example, it appears the program for other locations does not need to be tracked for PRC-004 evidence. Is this up to the entity to determine? **Response:** The proposed standard requires that the entity complete a Corrective Action Plan (CAP) for the identified Misoperation. The results of the entity's evaluation of other Protection Systems, including other locations is separate and distinct, and is meant to bring awareness to other areas of potential Misoperation. It is up to the entity's discretion in selecting other locations for evaluation and implementation of any modifications to other Protection Systems. Any action items placed in the CAP (including other locations) are required to be completed. No change made.

Organization	Yes or No	Question 4 Comment
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
City of Tallahassee	No	It can be difficult to perform some investigative actions if you are waiting for particular conditions to repeat in order to further investigate. You may not be able to repeat those conditions during the proposed time period from the standard. **Response:** Requirement R4 allows the entity to close its investigative actions. Should the particular conditions reoccur, the entity may use the information in the future. No change made.
Oncor Electric Delivery Company LLC	No	The Extenuating Circumstances process, as outlined on page 32 of the Application Guidelines, relies too heavily on a subjective review by Enforcement to determine whether penalties will be imposed. In alignment with the RAI project, Oncor recommends the evaluation of an Extenuating Circumstance be removed from the back end Enforcement phase and up to the Compliance Monitoring phase where the evaluation is done within a risk and controls framework. Furthermore, Oncor recommends the Registered Entity be

Organization	Yes or No	Question 4 Comment
		allowed to request a formal "state of extenuating circumstance" and coordinate an extension to the 120 day deadline with the Regional Entity. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (time frames) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made.
Ameren	No	(1) We request the drafting team add another example to clarify the paragraph on page 26, following Example 8b, which includes "...however, the standard remains applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection. **Response:** The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made. (a) Units in our GO's fleet shut down thousands of times each year, in our opinion Example 8a are applicable. Does the SDT intend to include these as correct operations if indeed the same reverse power relay also provides anti-motoring protection? **Response:** If the BES interrupting device operation is expected as part of a controlled shutdown, the operation is not included per the Applicability section of the standard. The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made.

Organization	Yes or No	Question 4 Comment
		(b) Our protection scheme in some cases will have separate Device 32 elements, with one short and one longer timer; does the SDT intend in these cases that only trips by the longer timer are within PRC-004 scope? GO will need to know as either of these differ from our understanding of NERC SPCS / RAPA guidance for reporting of total operations under the presently applicable PRC-004-2a. **Response:** Both of these 32 devices are part of the generator's Composite Protection System; both are applicable to the standard when operating as a protective function; neither are applicable when operating as a control function. The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made. (c) Based on the number of reverse power questions on your 2/20/2014 Webinar, it appears to us that many GO's are unclear on your intent. [Generator reverse power reporting clarity is another primary reason for our negative ballot.] **Response:** The drafting team provided clarification in the Application Guidelines under the section "Control Functions." Change made. (2) At the end of Example R4a on page 29, please add "Each of 3/24, 4/10, 5/27, and 8/29 actions are valid investigative actions." If the SDT intends otherwise, please state which ones are valid. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Public Service Enterprise Group	No	The Application Guide is unclear as to the reporting of reverse power relays. A reverse power relay is typically used to remove a generator from service (a control function) AND to prevent generator motoring (a protection function). The two are not separable. On p. 26, example 8a removes the operation of a generator's reverse power relay to open a breaker during routine shutdown from being subject to the standard because it is performing a control function, while the guideline then states "; however, the standard remains

Organization	Yes or No	Question 4 Comment
		applicable to the reverse power relay as a part of the generator Protection System when intended to provide generator anti-motoring protection." If the reverse power relay failed to open the generator's breaker during shutdown, the generator would motor and the breaker would need to be opened by manual intervention. As the SDT may know, reverse power relays have a documented "blind spot" that causes them to fail to operate during low power factor operation of the generator. (We can provide such documentation if desired). For this reason, generator operators normally have procedures with a step that states that the operator is to manually open the generator output breaker if generator the breaker does not open after a predetermined time period. If this occurred, would the failure of the reverse power relay be reported as a Misoperation? **Response:** If the GO includes the manual intervention as part of its process for a controlled shutdown, then it is not a Misoperation. In this case, it has clearly shown it is acting as a control function which is backed up by another control function. As noted, the same relay performs two functions – when the device is performing (or fails to perform) its protective function, that is when it is applicable to the standard. No change made. Finally, per the NERC document "Questions and Answers about Consistent Protection System Misoperation Reporting" dated February 5, 2013, reporting a reverse power relay Misoperation and not reporting a successful operation is inconsistent with the principle stated in paragraph #1 that "if an operation would not count as a misoperation, it should not be included as an operation." Therefore, to avoid further confusion, we recommend that reverse power relays used for equipment shutdown be explicitly eliminated from the scope of this standard. **Response:** Because of the inherent differences in the application of reverse power relays on generators continent-wide, the drafting team has provided the means to exclude them from the set of operations that will be reviewed by entities. The proposed standard's Applicability, Section 4.2.1, states: "Protective functions intended to operate as a control

Organization	Yes or No	Question 4 Comment
		function during switching are excluded."[5] Therefore, operations occurring within the entity's normal controlled process do not fall within the purview of the proposed standard. Any operation outside of an entity's shutdown sequence would be a reviewable operation. No change made.
Consumers Energy Company	No	Generally I agree with the proposed new definition of a Misoperation, but have one hypothetical circumstance where it might be unclear and could perhaps benefit from another example in the guidelines section. Under the category "Unnecessary Trip - Other Than Fault," the guidelines state that an operation that was initiated directly by on-site maintenance...is not a Misoperation. Are there circumstances where on-site maintenance could indirectly cause a Misoperation? We had a situation where a technician was conducting testing on a breaker failure (BF) relay, and accidently initiated the wrong BF relay in an adjacent panel that was still in service and not part of the testing plan for the day, resulting in tripping of the BES bus. Our initial thoughts were that the BF relay should have issued a 'retrip' function to its corresponding breaker after being initiated, thereby only tripping the one breaker instead of the entire bus. Investigation showed the relay was indeed designed to trip the bus and acted properly. BUT if the relay HAD operated improperly after being inadvertently initiated by on-site personnel, would that be a Misoperation? **Response:** According to the example presented above, this would not be a Misoperation due to the exemption in category 6 of the proposed definition. No change made. Does the presence alone of on-site personnel create an exemption in all cases? If that is the case, I think it should be explicitly stated, or another example added to clarify technician-induced operations.

[5] For additional information and examples, see the "Non-Protective Functions" and "Control Functions" sections in the Application Guidelines.

Organization	Yes or No	Question 4 Comment
		Response: This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Tacoma Power	No	On page 24 of the redlined Application Guidelines, remove the following verbiage: "This definition has been introduced in this standard and incorporated into the proposed definition of Misoperation to clarify that the entity must consider the entire Protection System associated with the BES interrupting device that operated. Additionally," This portion does not add value and seems to have a conflicting emphasis with the reminder of the paragraph. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. Regarding Example 4 in the Application Guidelines, Slow Trip - Other Than Fault, equipment damage is not explicitly identified in the definition of a Misoperation. Either the definition should be revised to clearly identify equipment damage or another example should be used that better fits the proposed definition. **Response:** The Application Guidelines (Example 4) has been revised to add clarity concerning this issue. The examples were moved to the Application Guidelines. Change made.
Southern California Edison Company	No	There continues to be a lack of clarity in the definition. The standards drafting team has created a term that does not provide clear means of compliance for the industry. **Response:** Thank you for your comment.
Xcel Energy	No	1) The examples for R6 in the Application Guidelines are not clear. In R6a, it states the CAP completed on 6/25/2014, but no action is referenced for this date. In R6b, it states the CAP completed on 10/28/2014 when a proactive only replacement program was established, but

Organization	Yes or No	Question 4 Comment
		in R6c and R6d, the CAP is open until the proactive replacement program is completed. It seems the difference between these two is only semantic. **Response:** The corresponding actions are found in the previous Requirement R5, Example R5a with at date of 07/01/2014. The examples R6c and R6d regarding preemptive replacement have been included in these Corrective Action Plans (CAP) for illustration. An entity may choose to handle other locations either within or separate of the CAP that is remedying the specific Misoperation cause(s). No change made. 2) Please clarify if it was the intent of the drafting team to exclude operations like the following example from being classified as a Misoperation: Assume that a fault occurs in a generator stator, due to either a mechanical or design setting issue the 64S does not operate. However, the 87 does operate and trips the unit. We believe this would not be a Misoperation because of the overall performance of the composite protection system. **Response:** The intent is to provide clarity that a single Protection System component failure is not a Misoperation so long as the overall performance of the Composite Protection System is correct. No change made.
Hydro-Québec Production	No	For the requirement R1, the other owner of the protection system shall share any information it has that could be used by the owner of the interrupting device to determine the cause of the misoperation of the interrupting device owner's protection system. For the requirement R2, the owner of the interrupting device shall share any information it has that could be used by the other owner of the protection system to determine the cause of the misoperation. **Response:** The drafting team agrees this is a best practice; however, it is not useful having a Requirement for each entity to share information. The way the Requirements are written, it is in the best interest of all parties (i.e., jointly owned Protection Systems) to share or communicate information about operations which meet the criteria for Requirement R1 and

Organization	Yes or No	Question 4 Comment
		R2. Having such a Requirement is administrative and provides little, if any, reliability benefit. No change made.
Indiana Municipal Power Agency	No	It is not clear how an entity is to show that an operation of a BES interrupting device happened fast enough and did not fall into one of the two "Slow Trip" categories of a misoperation. **Response:** The drafting team has modified the Slow Trip portion of the definition of “Misoperation” to address this concern. Change made.
Florida Power & Light	Yes	The examples are an excellent idea. It would also be advantageous and practical to include supporting information on the scope of Misoperation reporting. Example to consider adding: The boundary of Misoperation reporting extends from protective relay input devices to circuit breaker trip coil(s). **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[6] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made. More examples should be provided in relation to Power Generation events. **Response:** The Application Guidelines has been modified as suggested. Change made.
ACES Standards Collaborators	Yes	The examples in the Application Guidelines are improved and provide additional clarity.

[6] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Organization	Yes or No	Question 4 Comment
		Response: Thank you for your comment.
ReliabilityFirst Protection Subcommittee	Yes	Other than our suggestion from Question 2, our group would like to state that the concept of the Application Guideline is an excellent tool to retain the thought process behind the development of the standard. Its use in this and future standards will help greatly with the understanding, application, and consistency of the standards. **Response:** Thank you for your comment.
Manitoba Hydro	Yes	(1) PRC-004-3, Application Guidelines, Extenuating Circumstances - for clarity, replace the word “says” with the word “reads”. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made.
Entergy Services, Inc.	Yes	Look at response to question one. **Response:** Thank you for your comment.
Exelon	Yes	The concept of the Application Guideline (AG) is an excellent tool to retain the thought process behind the development of the standard. Use of an AG in this and future standards will help greatly with the understanding, application, and consistency of the standards. Generally, the applications are sufficient for the purpose. Specific comments for clarification include: In “Unnecessary Trip - Other Than Fault”, in the paragraph after Example 6d, the “on-site” maintenance activities section needs more clarity. Is the intent of that paragraph trying to say, if the BES Protection System equipment clearly misoperated and personnel had nothing to do with it, then it’s a PRC-004 misoperation. If the BES Protection System equipment appeared to misoperate, but it’s clear that personnel had something to do with that operation, it’s not a PRC-004 misoperation?

Organization	Yes or No	Question 4 Comment
		Response: This is correct and for the example above, both of these points are described in the Application Guidelines in the paragraphs preceding and following Example 6e. No change made. For a Communication System, does the "on-site" activities exemption apply to anywhere along the communication path were personnel caused what would otherwise look to be a BES Protection System misoperation? **Response:** According to the example presented above, this would not be a Misoperation due to the exemption in category 6 of the proposed definition. No change made.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Duke Energy	Yes	
Tennessee Valley Authority	Yes	
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company;	Yes	

Organization	Yes or No	Question 4 Comment
Southern Company Generation; Southern Company Generation and Energy Marketing		
Virginia State Corporation Commisison	Yes	
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	Yes	
PJM Interconnection	Yes	
Muscatine Power and Water	Yes	
American Transmission Company	Yes	
Idaho Power Company	Yes	
Kansas City Power & Light	Yes	
TransÉnergie Hydro-Québec	Yes	

Organization	Yes or No	Question 4 Comment
Northeast Utilities	Yes	
Seminole Electric Cooperative, Inc.	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Cowlitz PUD	Yes	
ITC	Yes	
Liberty Electric Power LLC	Yes	

5. **If you have any other comments on this Standard that you haven't already mentioned above, please provide them here:**

Summary Consideration: There were a number of comments that were relevant and consistent with responses found in the previous questions above and will not be summarized here. The most notable majority comment that resulted in a change was the Implementation Plan. The previous allowance of 24 months for the standard to become effective in the Western Interconnection was changed back to 12 months. This was changed because it was determined that a conflict does not exist between the proposed continent-wide PRC-004-3 and regional PRC-004-WECC-1 standards. Also, implementing the standard on the same time basis continent-wide eliminates any perceived preferential treatment. Minority comments included a number of editorial suggestions and edits which the SDT implemented.

The following summarizes comments which did not result in a change. One majority theme came from three comments supported by 22 individuals that had concerns about the population of BES interrupting device operation events that would be audited. The SDT noted that only those operations that meet the Requirement R1 criteria (i.e., 1.1, 1.2, and 1.3) are to be reviewed to identify whether a Misoperation occurred or not. The Reliability Standard Audit Worksheet (RSAW) also supports this approach and intent. Notable minority comments include approximately nine individuals that were concerned about timeframes, milestones, or closure of a CAP. The SDT responded that timeframes are needed to make the Requirement measurable and the CAP is closed by the entity based on its timetable. The commenters were concerned that the Regional Entities will no longer be involved with ensuring entities follow through on completing CAPs. Eight individuals were concerned about the cases where a Generatfaor Owner operates the Transmission Owner's BES interrupting device. The SDT noted that communication would need to occur and does occur today. Most of the BES interrupting device operations would be a result of synchronizing to the BES or a normal shutdown through a control function to remove the generating unit from service, both are not reviewable operations under Requirement R1. Approximately six individuals believed that Requirement R2 (i.e., "notification") is administrative and qualifies under the Paragraph 81 (P81) criteria as having little reliability benefit. The SDT contends that Requirement R2 has a reliability need to involve other owners that may need to review their Protection Systems for possible Misoperation. Approximately two comments supported by seven individuals argued that "manual intervention" in Requirement R1 is unnecessary because it is rare and should be requested by an auditor by exception. The SDT agrees that such situations are probably rare; however, the SDT contends this is a valid condition for which an entity must be required to identify any possible Misoperation of a BES Protection System. Last of the majority comments include four individuals that expressed concern over the Violation Severity Levels (VSL). Commenters were concerned about VSLs being unjust for larger entities. The SDT noted that the NERC VSL Guidelines were adhered to and do not unjustly impact larger entities. VSLs only come into scope during a potential violation, are per event, and not based on the size of an entity; therefore, are size-neutral.

Notable minority comments which did not result in a change include a request to add a field to the data request for reporting Misoperations, being clear the standard is not requiring Disturbance Monitoring Equipment (DME), and underfrequency load shedding (UFLS) only for BES Elements. The SDT provided feedback to NERC staff concerning the additional data request field for reporting. Also, the SDT contends that the standard and Application Guidelines provide the necessary points that DME is not required and that UFLS for BES Elements addresses the reliability concerns adequately.

Organization	Question 5 Comment
TransÉnergie Hydro-Québec	An addition “Field” can be added to improve metric analysis of microprocessor relays malfunction since these are the type of relays that will be installed in the future by every entities. As the number of microprocessor continue to grow, the more frequent will a Misoperation be caused by these type of relays, therefore this added field would greatly improve metric analysis. For example, the Field Value for a microprocessor relay malfunction could include the following: Setting Error - Incorrect Numerical Input Specified Setting Error - Incorrect User-Programmed Custom Logic Incorrect Design - Incorrect User Application Incorrect Design - Wiring Firmware Version Mismatch by User Others. **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[7] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made.
Cowlitz PUD	Applicability section 4.2.2 includes UFLS only if it trips a BES element. We believe that UFLS inclusion in this standard should only be applicable to those single UFLS elements that can have an adverse impact to the BES. Limiting applicability to UFLS elements which trip a BES element will not adequately address all UFLS adverse impact elements. For example, some industrial loads must be shed in a carefully planned sequence, and it may not be possible to link the UFLS trip signal to a BES element. Instead, the trip signal is received within the

[7] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

	industrial load (plant) whereby a controlled plant shutdown is automatically initiated. This load shedding can exceed 200 MW, and is significant. In such UFLS schemes, the actual process of the load shed within a non-BES plant should not be subject to standard compliance; however, the misoperation of the associated UFLS relay as a single point of failure should be considered as a significant BES support device. Inclusion of UFLS in this Standard may be duplicative of PRC-006-1, requirements R11, R12, and R13. An underfrequency event is generally a system wide event; conversely, the objective of Protection System action is to isolate an event to prevent it from becoming a system wide impact. UFLS elements must work as a coordinated system which can withstand several UFLS element failures, yet successfully stabilize the BES. Since PRC-004-3 addresses discovery of problems after an event, we propose that at best this Standard would assure UFLS element Unnecessary Trip misoperations would be mitigated. The discovery of a UFLS element Failure to Trip which has an adverse impact on the ability of the UFLS system to stabilize the BES as stated above is addressed by PRC-006-1. Notwithstanding the above, we do not see our concerns as requiring a negative ballot. **Response:** The drafting team contends that addressing underfrequency load shedding (UFLS) for Bulk Electric System (BES) Elements provides the necessary applicability for reliability. A UFLS relay that trips non-BES equipment (i.e., customer load or distribution) is a quality of service issue for the entity's customers and the impact on BES reliability is not measurable. The standard PRC-006-1 addresses UFLS program performance and will reveal potential Misoperations when evaluating the program's performance to a frequency excursion. Only UFLS relay operations directly impacting BES Elements need be included within the applicability of the proposed standard PRC-004-3. No change made.
Ameren	(1) Delete from R1 1.1 "or by manual intervention in response to a Protection System failure to operate;" and remove from Rationale for R1, and Process Flow Chart. This is an extremely rare occurrence not warranting special inclusion in the requirements. In our view, manual intervention is already included in that Failure to Trip is a Misoperations and a BES interrupting device did operate, albeit manually. It is acceptable to retain some mention or explanation of it in the Application Guidance to keep it from falling out of the consciousness. Unnecessary Trip - During Fault on page 24 already points out the correct remote clearing that would occur for a Fault. [Unwarranted inclusion of 'manual intervention' in a Requirement is another primary reason for our negative ballot.]

	Response: The requirement is written so that only manual interventions in response to a Protection System failure are required to be identified in addition to automatic operations of a Protection System. No change made. (2) Please add "Note: Historically, the cause of about of 10% NERC-wide Misoperations have an unknown cause" at the end declaration paragraph (2nd last paragraph) on page 29. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. (3) On page 31, please add "For completion of the CAPs in examples R5a through R5d see examples R6a through R6d on pages 33 and 34. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. (4) We understand R1 to apply to the aggregate set of BES interrupting device operations associated with the same BES event (e.g., fault, abnormal condition, etc.) For example, under present NERC SPSC guidance the entity count all trips in the automatic reclose cycle and reports them as a single event. **Response:** This portion of the Application Guidelines has been revised based upon the suggestion. Change made. (5) The NERC PSMTF Final Report recommended grouping all like events involving the same Protection System within a 24 hour period, recognizing that the response time limitations to altering the Protection System. SERC PCS advocated the 24 hour grouping in our comments to NERC on the Section 1600 Data Reporting draft. The resulting metrics more clearly indicate dominant causes, rather than being distorted by repetitive like events on the same Element and Protection System. **Response:** Please see the Application Guidelines, on multiple operations/same event/automatic recloses. Change made. (6) If the SDT intends that each and every BES interrupting device operations be separately tracked, the TO, GO, and DP certainly need to know this. Although every breaker operation is almost always available within the SCADA log attached in our PRC-004 software database, we group them into a single event record

	in accordance with applicable NERC guidance. We are concerned that if R1 intends we have a separate event record for each breaker operation, the administrative overhead is unwarranted and burdensome. **Response:** Please see the Application Guide under the heading "Requirement R1." The Protection System operation may be documented in a variety of ways such as in a report, database, spreadsheet, or list." The documentation may be organized in a variety of ways such as by BES interrupting device, protected Element, or Composite Protection System. No change made.
Texas Reliability Entity	(1) For Requirement R5, how does the SDT intend to handle a situation where the CAP involves another registered entity. For example, we've seen several cases where the CAP requires multiple TOs to make setting changes in order to mitigate the cause of the misoperation. In this case, should both TOs involved have their own CAP? **Response:** The entity whose Protection System component caused a Misoperation is required by the proposed standard to develop and implement a Corrective Action Plan (CAP). Part of the action within that CAP may include coordinating work such as settings with other entities. Coordination of settings also falls under the current Reliability Standard PRC-001-1 – Protection System Coordination. No change made. The requirement language is not clear. The bullet "Explain in a declaration why corrective actions are beyond the entity's control..." provides no assurance that all the required actions to mitigate the Misoperation are completed in cases where multiple entities are involved in the CAP. **Response:** Requirement R4 of the proposed standard is providing a mechanism for entities not to make corrective actions when such actions are not practical and will not improve reliability. See Examples R5e and R5f in the Application Guidelines. No change made. (2) Evidence Retention: We recommend changing the evidence retention from 12 months to a minimum of 3 years.

	Response: The drafting team based data retention on guidance provided by NERC staff for writing evidence retention periods. See pages 8 through 14 of the NERC Background Information for Quality Reviews, February 7, 2012 for more information.[8] No change made.
Manitoba Hydro	(1) R4, second bullet - for consistency with the previous bullet, rephrase to read "A declaration that no cause(s) were identified." **Response:** The drafting team does not agree that the suggestion provides additional clarity. No change made. (2) R5, second bullet - because it's possible that a single corrective action can be taken, add brackets around the "s" in the word "actions". **Response:** The drafting team does not agree that the suggestion provides additional clarity. No change made. (3) R6 and M6 - for consistency with other requirements in the standard, replace the word "actions" with "corrective action(s)". **Response:** The drafting team does not agree that the suggestion provides additional clarity. No change made. (4) R1 and R2 a. Use of the past tense (i.e. "that operated") is inappropriate for statutory / regulatory standards. The wording should be: "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device shall, within 120 calendar days of the operation of the BES interrupting device...". **Response:** Without the phrase "that operated" all BES interrupting device owners would have to investigate every BES interrupting device operation. No change made. b. Similarly, in R2.2 and 2.3, the word "determined" should be replaced with "has determined".

[8] http://www.nerc.com/pa/Stand/Resources/Documents/BackgroundDocument.pdf

	Response: Change made. c. Use of the word "when" implies a time frame. Given the intent, it would be clearer to use the phrase "under the following circumstances". **Response:** Change made. (5) R5 - for the reasons identified above, the use of past tense should be changed to:" Each Transmission Owner, Generator Owner and Distribution Provider that owns a Protection System Component that causes a Misoperation ...". **Response:** The use of "caused" is used to emphasize that the Misoperation has already been identified in the previous requirements. No change made. (6) The wording of R6 makes the compliance obligation unclear. Part of the requirement requires implementation of a CAP. However, another part of the requirement allows updating and changing the CAP. Accordingly, it can be inferred that some deviation from the CAP, and thus failure to implement the CAP, will still be considered compliance. A review of the Application Guidelines also confirms that rescheduling actions under the CAP is permitted in at least some cases. The criteria for acceptable revisions should be clarified in R6 (ex.- do they need to be beyond the reasonable control of the Responsible Entity?). **Response:** The Application Guidelines provide three examples of situations where reliability would not be improved. Requirement R5 addresses two situations where a CAP does not need to be developed and a declaration will be made. The definition of "CAP" limits the scope of the remedy to a specific problem; therefore, the drafting team contends that it is unlikely to be impractical to implement a CAP. No change made. Manitoba Hydro has concerns with the lack of clarity of Misoperation definition. Manitoba Hydro believes that the definition of Misoperation needs to be re-written for various reasons specified in the comments. **Response:** See responses in Question 1. For R4, Manitoba Hydro recommends the removal of the investigation frequency as repeated investigative actions would not be productive in identifying the cause of a Misoperation.

	Response: The proposed Requirement R4 provides the entity discretion on how to handle ongoing efforts. At least one investigative action is required toward determining the cause(s) of an identified Misoperation. Beyond that, the entity may declare it is unable to determine the cause(s). Whether the investigation is held open in anticipation of capturing similar operations, or if closed with a declaration, the entity should have the pertinent information documented both for future reference and compliance with the Requirement(s). No change made.
ACES Standards Collaborators	(1) We are concerned that Part 1.1 may cause an auditor to request an inventory of all BES interrupting device operations. From that list, then the applicable entity would be required to identify which BES interrupting device operations were cause by Protection System actuation and which were operator interventions. Then, the applicable entity may have to prove each BES interrupting device operation initiated by an operator was not necessitated by a Protection System Misoperation. Also, the applicable entity would have to show for each BES interrupting device operation caused by Protection System actuation was evaluated for Protection System Misoperation. **Response:** The drafting team structured the criteria in a manner to be clear that the audit population of BES interrupting device operations is those operations which meet the three criteria 1.1 through 1.3. This is further noted in the accompanying rationale box for this and the previous version of the proposed standard. The posted draft RSAW developed by NERC Compliance supports this approach. No change made. While we understand that an applicable entity will have to show it evaluated each BES interrupting device operation caused by a Protection System operation, we do not believe they should be required to identify those operations caused by other means such as a manual operation by the operator. To identify cases where manual intervention was necessary due to a Protection System misoperation, the applicable entity should be able to rely on its operator notifying the protection systems department that such actions were necessary. In other words, Part 1.1 should be evaluated based on this exception with the auditor only requesting the applicable entity to identify the instances where manual intervention was necessary. An explanation in the Application Guidelines for what is required here would be helpful.

	Response: The requirement is written so that only manual interventions in response to a Protection System failure are required to be identified in addition to automatic operations of a Protection System. No change made. (2) Requirement R1 needs to be further clarified for the situation when an entity is not able to identify if a Protection System operation was a correct operation or a Misoperation. This is particularly true for older technology such as electromechanical relays which may lack the necessary information to make such a determination. As the requirement is literally written, it requires the entity "to identify whether its Protection System component(s) caused a Misoperation." If an entity is unable to determine a whether the relay operated as designed, then the requirement would be technically violated. The VSL for R3 results in a severe violation if the responsible entity failed to identify a Protection System Misoperation. There should be some flexibility for instances where the operation is unknown. **Response:** The intent of the definition of "Misoperation" and the standard is to classify an operation as a Misoperation if the available information leads to that conclusion. The standard also allows an entity to classify an operation as a Misoperation if an entity is not sure. It may decide to identify the operation as a Misoperation and continue its investigation. If the continued investigative actions are inconclusive, the entity may declare no cause can be found and end its investigation. The Application Guidelines section has been updated to address this issue. Change made. (3) While we believe that R2 meets P81 criteria and should be removed, if the requirement persists, we recommend removing the Distribution Provider from the requirement. By definition, the Distribution Provider cannot own a "BES interrupting device" since it is a BES Element as explained on page 21 in the Application Guidelines. The Distribution Provider provides the wires between the BES and the end-use customer. It is the TO/TOP that owns/operates an integrated transmission Element that is 100 kV or higher. This is consistent with statement of registry criteria and the BES definition. If a Distribution Provider does own a BES interrupting device, then they will also be registered as a TO. Furthermore, the Application Guidelines state that the BES interrupting device is not part of the Protection System so there is no reason for the Distribution Provider to apply. **Response:** Requirement R2 ensures notification of those who have a role in identifying Misoperations, but were not accounted for within Requirement R1. No change made.

	Response: The drafting team agrees that a Distribution Provider (DP) which owns Bulk Electric System (BES) interrupting device should be registered as a Generation Owner or Transmission Owner (TO) as the case may be. However, in this case, the DP may own a non-BES Protection System which operates a BES interrupting device. This is why the drafting team has included the DP as an applicable entity. No change made. (4) For the second severe VSL of R3, "a Misoperation its Protection System" should be "a Misoperation in its Protection System." The "in" is missing. **Response:** The drafting team does not agree that the suggestion provides additional clarity. No change made. (5) We disagree with the VRFs for R2. It is an administrative requirement and should not even be a requirement since it meets P81 criteria. However, if the requirement persists, the VRF should be no higher than "Low" since it is administrative. **Response:** Requirement R2 is not purely administrative since without a mandatory reporting to other owners as defined in R2, there is no expectation of performance by the other owners as prescribed in Requirement R3. No change made. (6) Thank you for the opportunity to comment.
MRO NERC Standards Review Forum	: The NSRF is concerned about the potential inadvertent inclusion of individual wind turbines in this standard where the inclusion of thousands of individual wind turbine protection systems will add significant burden without corresponding reliability benefits. The NSRF also recognizes the NERC dispersed generation SAR and SAR team are best equipped to address this issue. **Response:** The Misoperations drafting team understands the concern with the applicability of dispersed generation resources (DGR) to this standard. This drafting team is working with the DGR drafting team addressing standards with this concern under Project 2014-01 – Standards Applicability for Dispersed Generation Resources. In order to keep the sequence of the versions correct, the DGR drafting team will consider the exclusion in this standard once approved by industry. This should not be of great concern due

	to the implementation time of this standard and the need to bring in alignment with the work of the DGR drafting team. No change at this time.
SERC Protection and Controls Subcommittee	1. The removal from R1 of the qualifier of an operation 'device operation caused by a Protection System operation' has some consequences that were not likely intended by the drafting team in that, as presently written, every operation on a BES interrupting device becomes into scope of this standard. It includes both automatic and manual operations. It is also noted that this description would also exclude those cases that may be a failure to trip. **Response:** The drafting team agrees with your perception of its intent. The posting retained in Requirement R1, Part 1.1 the concept that the interrupting device operations that need to be evaluated were caused by a Protection System. Only interrupting device operations caused by Protection System operations (except those specifically exempted) and manual operations made in response to a Protection failure are within the scope of Requirement R1 in the Standard. No change made. Requirement R2 was revised to address the case where an entity's BES interrupting device provided backup protection. Part 2.2 of Requirement R2 requires this entity to notify the entity that backup protection was provided which is most likely due to a failure to operate. Change made. 2. Related to the observation in #1 above, this would also bring the TOP and GOP into the scope of this standard since the TOP and GOP would need to provide the TO every operation of a BES interrupting device and indicate which were manual vs. automatic in nature. As such the Applicability would need to be modified to include the TOP and GOP. **Response:** The drafting team agrees adding in the Transmission Operator and Generator Operator provides little to no reliability benefit. The proposed standard's applicable entities should be capable of acquiring this necessary information from others, if necessary. No change made. 3. The added change of including 'or by manual intervention in response to a Protection System failure to operate' additionally is data needed from the TOP and GOP. Although not necessarily a common occurrence by the TOP, this may happen by the Plant Operator on a more common basis. As such there would be the need for each GOP/ Plant Operator by polled quarterly to provide this information. This addition is not necessary since the initiating event for such action would be a failure to operate. However,

	if this part of the Requirement remains, the Applicability would need to be modified to include the TOP and GOP. **Response:** The drafting team agrees adding in the Transmission Operator and Generator Operator provides little to no reliability benefit. The proposed standard's applicable entities should be capable of acquiring this necessary information from others, if necessary. No change made. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Protection and Control Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Southern Company: Southern Company Service, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	1. The removal from R1 of the qualifier of an operation 'device operation caused by a Protection System operation' has some consequences that were not likely intended by the drafting team in that, as presently written, every operation on a BES interrupting device comes into scope of this standard. It includes both automatic and manual operations. It is also noted that this description would also exclude those cases that may be a failure to trip. **Response:** The drafting team agrees with your perception of its intent. The posting retained in Requirement R1, Part 1.1 the concept that the interrupting device operations that need to be evaluated were caused by a Protection System. Only interrupting device operations caused by Protection System operations (except those specifically exempted) and manual operations made in response to a Protection failure are within the scope of Requirement R1 in the Standard. No change made. The drafting team contends that the "failure of a Composite Protection System to operate for a Fault" provides sufficient guidance to determine if a "Failure to Trip" occurred. The operation of other zones to prevent the event from propagating should be considered along with the other available evidence. No change made. 2. Related to the observation in #1 above, this would also bring the TOP and GOP into the scope of this standard since the TOP and GOP would need to provide the TO every operation of a BES interrupting device and indicate which were manual vs. automatic in nature. As such the Applicability would need to be modified to include the TOP and GOP.

	Response: The drafting team agrees adding in the Transmission Operator and Generator Operator provides little to no reliability benefit. The proposed standard's applicable entities should be capable of acquiring this necessary information from others, if necessary. No change made. The added change of including 'or by manual intervention in response to a Protection System failure to operate' additionally is data needed from the TOP and GOP. Although not necessarily a common occurrence by the TOP, this may happen by the Plant Operator on a more common basis. As such there would be the need for each TOP and GOP/ Plant Operator by polled quarterly to provide this information. This addition is not necessary since the initiating event for such action would be a failure to operate. However, if this part of the Requirement remains, the Applicability would need to be modified to include the TOP and GOP. Note: related to above 3 comments: Although the recently posted RSAW mitigates some of these concerns, we feel the Standard itself should be modified to go back to the concept of 'BES interrupting device operation in its Facility caused by a Protection System operation, identify and review each Protection System operation' thus removing the need to include the TOP in the applicability. **Response:** The drafting team agrees adding in the Transmission Operator and Generator Operator provides little to no reliability benefit. The proposed standard's applicable entities should be capable of acquiring this necessary information from others, if necessary. No change made. 3. The various timetables introduced in the Standard result in many compliance milestones to be tracked for minimal if any overall increase in reliability. There is no evidence that entities have not been doing due diligence in investigating and correcting misoperations, therefore, the addition of the various timelines serve only to generate additional paperwork. **Response:** The time periods in the standard are maximums for completing work relative to each Requirement and the drafting teams contends they are reasonable. Dates should be included in the entity's evidence of completion for each Requirement. The only exception to this is demonstrating the investigative actions in Requirement R4 which occur on a periodic basis. This time period is essentially six months and is minimal for the overall number of unidentified causes that go beyond the initial 120 calendar days from the operation of the BES interrupting device. No change made.

	4. We also observe that the Standard does not require any closure on a specific event. As noted in R6: implement each CAP developed in Requirement R5, and update each CAP if actions or timetables change, until completed. Therefore, an acceptable CAP could be 'we plan on upgrading the protection systems in 15 years which will solve the problem'. Since the neither proposed actions nor timetable may change, no update is required. This seems to contradict the statement in the Rational box for R6 which states: Documenting changes or completion of CAP activities provides measurable progress and confirmation of completion. **Response:** The example provided is not practical nor is it consistent with the definition of Corrective Action Plan (CAP) and the examples provided in the proposed standards' Application Guidelines for both Requirement R5 and R6. No change made. 5. Related to comment #4 above, which notes that there is no requirement for closure: Recognizing that there has been considerable work by various NERC teams (SPCS, RAPA, and the PSMTF) to implement consistent reporting utilizing the misoperation template and that one of the recommendation was that the Regional entities need to become closely engaged in reviewing submittals and following up on action plans/ corrective actions; we would encourage the SDT to consider revamping the Standard to require the quarterly submittal of misoperation data utilizing the approved template and NERC and the Regions to agree on some standard methodology for Regional review and follow-up if progress is not being made. **Response:** The effectiveness of a CAP would be apparent in the number of recurring events of a similar nature. It is expected that entities would seek solutions for Protection System Misoperations that prevent recurrence. The drafting team understands when the patterns of Protection System Events indicate increasing recurring events of a similar nature there is value in having Corrective Action Plans (CAP) reviewed by others and in some cases the Regional Entities are currently performing these activities. Also, a Reliability Standard Requirement cannot be applicable to the Regional Entity; therefore, this entity would not be mandated to do such reviews. The drafting team expects that entities will facilitate reviews of Protection System operations, Misoperations, and/or CAPs this through peer review groups or industry forums. No change made. The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data

	submittals and the associated template.[9] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made.
Tri-State Generation and Transmission Association, Inc.	1. The standard is difficult to interpret regarding jointly-owned Composite Protection System components as opposed to multiple entities owning separate components. An interrupting device and all or part of the Composite Protection System may be owned by a contractually-organized group that is not a registered Functional Entity. This makes it unclear which entity is responsible for initial review and potential notification under Requirement R1. Our belief is that it would be the registered entity that is contractually responsible for operating the interrupting device. **Response:** While a Protection System may be contractually owned by multiple entities that are not jointly registered, all of the entities would ultimately be responsible for the requisite documentation and results. Contractually organized entities may share or designate compliance responsibilities as well as associated documentation. No change made. 2. It is also unclear whether Requirement R2 includes notice to all the other joint-owners of the Protection System or only to the owners of the Protection System components that are not owned by the joint group. Our belief is that notice should only be given to the owners of the Protection System components that are not owned by the joint group. Our proposal to eliminate the uncertainty is to add a statement to the Applicability that addresses how jointly-owned Facilities are to be handled in the standard any time a TO, GO, or DP has a responsibility. **Response:** The standard requires notification to the other owner(s) when a Misoperation occurs or cannot rule out a Misoperation and the owner's Protection System component did not cause the Misoperation. There is no exclusion for components that are owned by multiple discrete entities. The challenges of delineating compliance responsibility for contractually joined entities would be extremely difficult and outside the scope of Standard Drafting Team. No change made.

[9] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Puget Sound Energy	a) Under Facilities on p.5, UFLS /UVLS should both be listed, if intended. The order of facilities (specifically content of 4.2.1 and 4.2.2) should be swapped - so that everything INcluded comes before everything EXcluded. **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. b) There should be a whole section clarifying exclusion of SPS/RAS (but inclusion of UFLS/UVLS). Or....the definition of SPS/RAS should be changed to include UFLS/UVLS. **Response:** The Background section states "Misoperations associated with Special Protection Schemes (SPS) and Remedial Action Schemes (RAS) are not addressed in this standard due to their inherent complexities." Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). An exclusion for RAS/SPS has been added to the Applicability section. Change made. c) A Misoperation Process Benchmark table of reporting functions and dates should be provided to entities. This would greatly facilitate retention of misoperation timeline evidence (for audits, self-cert, data requests). The Misoperation Process Benchmark table structure could be provided by the Regional Entities such as WECC in an updated misoperation Criterion as an Appendix. A suggested list of Benchmark dates is as follows: 1. date of Interrupting device operation, 2. date of identification of misoperation, 3. date other owners of Protection System (of BES interrupting device operation) notified, 4. date of identification by notified entity whether its device caused a misoperation, 5. date the cause of misoperation investigated/found,

	6. date of further investigation (if cause not found) 7. date of Corrective Action Plan (CAP) development 8. target CAP completion date(s), actual CAP completion date **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[10] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. The drafting team has forwarded your suggestion to the appropriate NERC staff for consideration. No change made. d) Finally, it is recommended that Quarterly Misoperation Reporting be changed over to a "Data Request" sooner than the effective date of PRC-004- **Response:** The drafting team agrees that in theory this sounds like a good idea; however, Regional Entities and NERC may need the allotted implementation period to address changes in data collection and practices that will be effectuated by the proposed standard. This is especially true with NERC developing the systems for collecting data rather than the Regions. No change made. 3. It is stated on page 5 of the proposed PRC-004-3, that the currently reporting system is "not optimal to establish consistent metrics for measuring Protection System performance". Perhaps the ERO Reliabililty Assessment and Performance Analysis Group could release an updated recommendation letter for Misoperation Reporting. It is also recommended that the Misoperation "Data Request" occur once per year. **Response:** The data reporting will be addressed by a NERC Rules of Procedure, Section 1600 Request for Data or Information (i.e., data request). See the proposed data request for details regarding periodic data submittals and the associated template.[11] The Section 1600 Data Request will be submitted for approval along with the revised PRC-004 Reliability Standard. No change made.

[10] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

[11] http://www.nerc.com/pa/RAPA/Pages/Protection-System-Misoperations-Section-1600-Data-Request.aspx

Northeast Power Coordinating Council	a. The "Effective Dates" section of the standard is confusing as it suggests no regulatory (i.e. FERC) approval is required in Western Interconnection and offers both twelve and twenty-four month timeframes. **Response:** After further review and discussion with WECC following the latest changes to the standard, the proposed standard and the existing regional standard do not conflict. Therefore, different implementation timeframes are no longer necessary. However, the language used in the implementation plan is the stock language NERC uses for effective dates of Reliability Standards. In the prior version of the implementation, the effective dates were specified separately for WECC to provide time to eliminate language conflicts between the proposed standard and the regional standard. Since no conflict exists, there will be a single effective date for the standard. Change made. b. Applicability Section - Facilities: We agree with removing references to RAS and SPS, but question the omission of UVLS when UFLS that is intended to trip one or more BES Elements is included. There might well be UVLS that performs a similar function when initiated by abnormal voltage conditions. The draft standard does not provide any rationale for the omission. Please review and provide the rationale, or add UVLS to the list of applicable facilities. **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. c. Measure M1: M1 as presented only indicates the kind of evidence that can be provided to demonstrate compliance by the responsible entity, but M1 does not specify the performance targets to illustrate compliance, e.g. "that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when the conditions in Part 1.1 to Part 1.3 are met". Suggest M1 be revised to provide the performance target. **Response:** The Measures have been updated. Change made. d. VSL for R1: The second condition under SEVERE is not proper or needed. Requirement R1 asks for the identification of whether or not a responsible entity's Protection System component(s) caused a

	Misoperation but R4 has a provision that if the responsible entity has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 (or R3), then it shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters. Therefore, the second condition under SEVERE is either premature or inappropriate. We suggest to remove the second condition, or to revise it to read: The responsible entity did not take action to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1. **Response:** The drafting team followed the VSL guidelines in proposing VSLs. The requirement is binary, either the entity identified the operation as a "Misoperation" or not. Under the VSL guidelines, this condition requires the VSL to be Severe for failure to perform the activity. Additionally, the drafting team has provided gradated VSLs for tardiness in identifying any Misoperation. No change made. e. VSL for R3: Second condition under SEVERE - similar comment as for the VSL for R1 preceding. **Response:** The drafting team followed the VSL guidelines in proposing VSLs. The requirement is binary, either the entity identified the operation as a "Misoperation" or not. Under the VSL guidelines, this condition requires the VSL to be Severe for failure to perform the activity. Additionally, the drafting team has provided gradated VSLs for tardiness in identifying any Misoperation. No change made. f. The SDT should reconsider the need for the defined term "Composite Protection System". By definition, a Protection System is already a composite system whose components need to function collectively to protect an Element. The proposed term is redundant. The comment report indicated that 4 commenters representing 24 individuals requested clarification of the term "composite Protection System". This represents a very low percentage of the total number of commenters and individuals, which should not be the basis for proposing the redundant new term. **Response:** The reason for proposing the newly defined term, "Composite Protection System," is found in the Application Guidelines under the heading "Definitions." No change made.
Independent Electricity System Operator	a. Applicability Section - Facilities: We agree with removing references to RAS and SPS, but question the omission of UVLS when UFLS that is intended to trip one or more BES Elements is included. There might well be UVLS that performs similar function when initiated by voltage conditions. The draft standard does

	not provide any rationale for the omission. Please review and provide the rationale, or add UVLS to the list of applicable facilities. **Response:** Undervoltage load shedding (UVLS) has not been included in the proposed PRC-004-3 standard's Applicability because Misoperations of UVLS relays are being addressed under Project 2008-02 – Undervoltage Load Shedding when modifying Reliability Standard PRC-022-1 – Under-Voltage Load Shedding Program Performance. Since UVLS does not fall under 4.2.1 or 4.2.2, it is not applicable to PRC-004-3. No change made. b. Measure M1: M1 as presented only indicates the kind of evidence that can be provided to demonstrate compliance by the responsible entity, but M1 does not specify the performance targets to illustrate compliance, e.g. "that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when the conditions in Part 1.1 to Part 1.3 are met". Suggest M1 be revised to provide the performance target. **Response:** The Measures have been updated. Change made. c. Measure M2: Similar comment as for M1, above. The performance target is that the responsible entity notified the other owner(s) of the Protection System of the operation of the BES interrupting device when the conditions in Parts 2.1 to 2.3 are met. **Response:** The Measures have been updated. Change made. d. Measure M3: Similar comment as for M1, above. The performance target is that the responsible entity undertook actions to identify whether its Protection System component(s) caused a Misoperation when notified by the other owner of the Protection System of the BES interrupting device that operated. **Response:** The Measures have been updated. Change made. e. Measure M4: Similar comment as for M3, above. The performance target is that the responsible entity performed investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters after the Misoperation was first identified, and the identification of the cause(s) of the Misoperation or a declaration that no cause was identified. **Response:** The Measures have been updated. Change made.

	f. VSL for R1: The second condition under SEVERE is not proper or needed. Requirement R1 asks for the identification of whether or not a responsible entity's Protection System component(s) caused a Misoperation but R4 has a provision that if the responsible entity has not determined the cause(s) of a Misoperation identified in accordance with Requirement R1 (or R3), then it shall perform investigative action(s) to determine the cause of the Misoperation at least once every two full calendar quarters. Therefore, the second condition under SEVERE is either premature or inappropriate. We suggest to remove the second condition, or to revise it to read: The responsible entity did not take action to identify whether or not its Protection System component(s) caused a Misoperation in accordance with Requirement R1. **Response:** The drafting team followed the VSL guidelines in proposing VSLs. The requirement is binary, either the entity identified the operation as a "Misoperation" or not. Under the VSL guidelines, this condition requires the VSL to be Severe for failure to perform the activity. Additionally, the drafting team has provided gradated VSLs for tardiness in identifying any Misoperation. No change made. g. VSL for R3: Second condition under SEVERE - similar comment as for VSL for R1, above. **Response:** The drafting team followed the VSL guidelines in proposing VSLs. The requirement is binary, either the entity identified the operation as a "Misoperation" or not. Under the VSL guidelines, this condition requires the VSL to be Severe for failure to perform the activity. Additionally, the drafting team has provided gradated VSLs for tardiness in identifying any Misoperation. No change made.
American Electric Power	AEP believes the draft is very close to being ready for final ballot. AEP supports the overall efforts of the drafting team in the fundamental approach taken in the proposed standard. Our negative vote does not reflect disagreement on the direction or intent of the standard. Rather, it is driven by a number of smaller issues that, in total, would prove problematic in consistently applying the standard. **Response:** Thank you for your comment.
David Kiguel	As written, the draft standard leaves a void that should be filled. A mechanism must be provided to allow for verifying that the conclusions of the investigation are correct, the CAP is appropriate and overseeing its completion within the planned time.

	Typically, this would be a responsibility that could be assigned to the Reliability Assurer (RA) as defined in the BoT approved Functional Model. The FM definition of RA fits this role well. However, since no entities are registered as RA at this time and it is unlikely there will be in the future, a second choice would be assigning such responsibility to the Planning Coordinator (PC). Suggest adding an additional requirement assigning such responsibility to the RA (or the PC if the SDT decides so): Each Transmission Owner, Generator Owner, and Distribution Provider that owns the Protection System component(s) that caused the Misoperation shall submit its investigation report and CAP documentation to the Reliability Assurer (or Planning Coordinator) that has responsibility for the area in which the associated devices are located, within 21 calendar days of their completion. The RA (or PC) shall review and either approve or provide comments within 60 calendar days of the submission. **Response:** The drafting team understands the value of having Corrective Action Plans (CAP) reviewed by others and Regional Entities. However, a Reliability Standard Requirement cannot be applicable to the Regional Entity The Planning Coordinator does not have the expertise to review these CAPs. No change made.
CenterPoint Energy Houston Electric LLC	CenterPoint Energy recommends revising the wording of the second bullet of Requirement R5 to account for situations where corrective action would not be practical. CenterPoint Energy suggests the following wording: ‘Explain in a statement why corrective actions are beyond the entity’s control or would not improve BES reliability or may not be practical, and that no further corrective actions will be taken.’ **Response:** The Application Guidelines provide three examples of situations where reliability would not be improved. Requirement R5 addresses two situations where a CAP does not need to be developed and a declaration will be made. The definition of “CAP” limits the scope of the remedy to a specific problem; therefore, the drafting team contends that it is unlikely to be impractical to implement a CAP. No change made.
Xcel Energy	Definition for Unnecessary Trip - Other Than Fault: The first sentence of this is unclear (triple-negative) without the expanded language in the Application Guidelines section. Consider omitting the clause “...for which it is not designed” to make this more clear.

	Response: The drafting team removed the "for which it is not designed" language. Change made. The analysis of a Failure to Trip situation does not appear to be covered here, except to the extent that another interrupting device trips in a different zone to prevent the event from propagating. **Response:** Requirement R2 has been modified by adding Part 2.2 to address these concerns. Change made. The drafting team contends that the "failure of a Composite Protection System to operate for a Fault" provides sufficient guidance to determine if a "Failure to Trip" occurred. The operation of other zones to prevent the event from propagating should be considered along with the other available evidence. No change made.
SPP Standards Review Group	Exclusions for SPS and RAS are mentioned in the Rationale Box for Applicability. If these exclusions are not incorporated in the RSAW, which was just recently posted and we have not had a chance to review, then the exclusions should be included in the applicability section of the standard. **Response:** Remedial Action Schemes (RAS) and Special Protection Systems (SPS) are being addressed by Project 2010-05.2 – Special Protection Systems (Phase 2 of this project). An exclusion for RAS/SPS has been added to the Applicability section. Change made. Typos/grammatical/editorial: In the last line of the 4th paragraph on Page 5 under the Background section, insert 'be' between 'to' and 'independent'. Insert 'of' in both portions of the Moderate VSL of R5 between 'days' and 'first'. Application Guidelines In the definition of Composite Protection System on page 21, change the 'a' in front of 'Element' to an 'an'. In the 1st paragraph under Requirement R1 on Page 27, delete the 'that' following 'identified' in the next to last line of the paragraph. In Example R2a under Requirement R2 on Page 28, set the phrase 'or DCB relaying' off with commas. In the last line of the last paragraph under Requirement R3, insert an 'as' between 'such' and 'an'.

	In the 2nd line of the 1st paragraph under Requirement R4 on Page 28, delete 'the entity' following 'notified,' in the 2nd line. It would be helpful to include the initiating event in Examples R4b and R4c.Hyphenate 'in-service' in the 3rd line of Example R4c on Page 30. In the 1st paragraph under Requirement R5 on Page 30, delete the 'or' and place parentheses around CAP in the 2nd line. Reword the 1st line of the 3rd paragraph under Requirement R5 on page 30 to read: 'The time periods within Requirements R1, R3 and R5 are distinct...' On Page 31 in the introductory paragraph for Examples R5a, R5b and R5c, insert 'in the relay' in the 2nd line of the paragraph following 'capacitor'. Also, in the examples, rewrite the sentence that states 'Replace capacitor.' to say 'Replace the capacitor.' We suggest the introductory paragraph for Examples R5g, R5h and R5i on Page 32 be rewritten to state: The following are examples of a declaration why corrective actions would not improve BES reliability.' In Example R5i on Page 32, spell out POTT. In Examples R6a, R6b and R6c on Pages 33 and 34, change the sentence in the 2nd line of both examples from 'The failed capacitor...' to 'A failed capacitor...' Delete the semicolon in the 2nd line of the last paragraph on Page 33. To eliminate any possible confusion, change the CAP completion date in Example R6c from 03/09/2015 to 03/01/2015. The example gets messy if the completion date is actually after the scheduled completion date. **Response:** The above suggestions have been addressed. Changes made.
FirstEnergy Corp	For FirstEnergy, the "BES interrupting device" (GCB or Generator Circuit Breaker) is typically owned by the TO, due to the location of the POI (Point of Interconnection). However, the Protection System devices which operate the GCBs are owned by the GO. Regardless the ownership, the GO certainly knows when the "BES interrupting device" (GCB) operates. It appears that a significant emphasis of this revision is to

	ensure the owner of the BES interrupting device and the owner of the Protection System devices which operate the BES interrupting device are communicating and collaborating in the evaluation. It would seem that the detailed effort to ensure this provides more confusion than clarification for the GO. **Response:** While the situation provided is not uncommon, there are far more cases involving TO-TO interconnections where a clear understanding of accountabilities is required. No change made.
Ingleside Cogeneration, L.P./Occidental Chemical Corporation	ICLP is concerned that Compliance Enforcement Entities' interpretation of PRC-004-3 will evolve over time - particularly as new Protection System vulnerabilities are found through the evaluation of Misoperations. In addition, the need for greater numbers of measuring points and the increased granularity of Disturbance data will naturally grow as relay schemes become more and more complex. This means that a clear expectation of the requirements for Disturbance Monitoring Equipment (DME) must be established up front in a binding fashion. We accept the project team's assertion that PRC-002-2 (presently under development) is the proper vehicle for the identification of required DME locations, but would like to see a clear tie to PRC-004-3. Otherwise it is easy to see that CEAs may decide at a future date that Misoperations' reporting needs are the driving factor for DME, not PRC-002-2. **Response:** The standard does not require the use of DME to determine whether a Misoperation has occurred; however, if DME are available, then they can be used to make the determination. The drafting team contends that PRC-004-3 does not require the installation of DME to assess interrupting device operations. No change made.
Florida Municipal Power Agency	In general, FMPA disagrees with the philosophy of the current standard. Protection system design is too complex, too diverse, and requires too much engineering judgment to be conducive to making all system designs and voltage classes of systems fit into one set of criteria. Many of the comments the PSM SDT has been receiving are evidence to that effect. System Protection is just as much an art as it an engineering science (i.e., "The Art and Science of Protective Relaying", C. Russel Mason, Wiley, 1956). FMPA supports the intent of the statements that the SDT has laid out which seek to provide the individual entities with the ability to provide engineering judgment, but there is no clear cut way to establish measures and allow entities to demonstrate compliance without a set of specific criteria against which the comparison can be made. Thus, FMPA believes entities should have "Protection System Design Philosophies" for their systems as appropriate, analogous to the FAC-008-3 and the prior FAC-008-1 and 009-1 standards and facility Rating

	Methodologies. Entities can lay out the characteristics of their systems - what is the "intended operation" for the systems, and what, generically, constitutes the constraints around which that entity develops its Composite Protection Systems. We recognize the tremendous amount of work the PSM SDT has put forth in attempting to reach industry consensus on this document but do not believe any form of document that applies criteria without a corresponding philosophy behind that criteria makes the standard too ambiguous. In recognition of the art of protective relaying, we suggest documenting a protection philosophy and intended operation of systems against which to measure whether a protection system operates as intended or not. **Response:** The drafting team contends "operate as intended" is illustrated by the Misoperation definition. An Element's total complement of protection needs to operate dependably and securely. The Application Guidelines has been revised to add clarity concerning this issue. Change made.
Nebraska Public Power District	It seems like the scope for the CAP that must include an evaluation of other Protection Systems including other locations to be completed is very open ended. The concern is what an audit team's latitude will be with reviewing and accepting or not accepting the subjective nature or these evaluations for other locations. Can the SDT comment how an evaluation that was completed for other locations as part of a misoperation might be addressed in an audit? For example, if a misoperation occurs due to a setting error and an entity decides not to review every relay setting on their system is it possible for an audit team to disagree with this evaluation and create any potential violations? **Response:** The drafting team is not in a position to state how an audit team may or may not determine compliance; however, the draft RSAW available on the NERC web page for this standard may be helpful in answering these types of concerns. The Application Guidelines provide guidance to the extent of evaluating other locations. No change made. The Protection System owner is responsible for determining the extent of its evaluation concerning other Protection Systems and locations." **Response:** Yes, guidance is provided in the Application Guidelines under section heading "Requirement R4." No change made.

	It is recommended the section 1600 Misoperation Draft Template language should match PRC-004-3. It would be quite odd to have the evaluations requirements and a data submissions request use different language. **Response:** The data reporting was split off from the standard, in part, to provide flexibility to make changes to the reporting template as needed to further the analysis of Misoperations. Therefore, the drafting team cannot guarantee that the reporting template will match the standard. The portion of R6 that states "and update each CAP if actions or time tables change, until completed" seems excessive and granular in nature and adds a lot of detail tracking and difficulty in auditing. It is enough to require a corrective action plan be implemented and close the plan when the final objectives are completed. R4 provides the long term tracking and scheduling. This portion of R6 should be removed. Another option would be to use similar language as in R4. **Response:** Requirement R4 requires determining the cause of the Misoperation, but does not involve a CAP. Requirement R5 requires developing a CAP. The language you reference in Requirement R6 is included to give an entity leeway to revise their proposed corrective actions or timetables if new developments or unforeseen circumstances warrant. No change made.
Muscatine Power and Water	MP&W is concerned about the potential inadvertent inclusion of individual wind turbines in this standard where the inclusion of thousands of individual wind turbine protection systems will add significant burden without corresponding reliability benefits. MP&W also recognizes the NERC dispersed generation SAR and SAR team are best equipped to address this issue. **Response:** The Misoperations drafting team understands the concern with the applicability of dispersed generation resources (DGR) to this standard. This drafting team is working with the DGR drafting team addressing standards with this concern under Project 2014-01 – Standards Applicability for Dispersed Generation Resources. In order to keep the sequence of the versions correct, the DGR drafting team will consider the exclusion in this standard once approved by industry. This should not be of great concern due to the implementation time of this standard and the need to bring in alignment with the work of the DGR drafting team. No change at this time.

JEA	R1 & R3 both need an exclusion for any declared natural disasters. **Response:** NERC and the Regional Entity do not have the authority to provide flexibility regarding the performance (time frames) of a Reliability Standard in unique extenuating circumstances. However, the Sanction Guidelines of the North American Electric Reliability Corporation, Section 2.8, Extenuating Circumstances, says: "In unique extenuating circumstances causing or contributing to the violation, such as significant natural disasters, NERC or the Regional Entity may significantly reduce or eliminate Penalties." While the drafting team recognizes the concern and that there are other standards which have similar provisions for natural disasters, the sanction guidelines provide sufficient flexibility to address extenuating circumstances in the event that they occur. No change made. We also believe that the 60 day timeframe identified in R5 to develop a Corrective Action Plan and evaluate applicability is not sufficient to consider applicability to other PS, different options and their cost/benefit scenarios, coordinate resources, develop schedules, and procure funding. We recommend this be changed to 180 days. **Response:** The drafting team believes that 60 days is sufficient to develop a CAP including its applicability to other Protection Systems as there is opportunity to update the CAP in Requirement R6 as needed. The drafting team believes that issues such as cost/benefit scenarios, resource coordination, scheduling, and funding procurement can be considered while developing the schedule of the CAP. No change made.
US Bureau of Reclamation	Reclamation thanks the drafting team for their efforts refining the standard and providing the examples in the Application Guidelines. **Response:** The drafting team thanks you for your comment.
Entergy Services, Inc.	Required Protection System Misoperation identification and evidence in support of R1 could be interpreted to include all scheduled or manual interrupting device operations, which we believe is not and should not be the intention. Either way, suggest rewording R1 to include the applicable Protection System governing criteria by integrating R1.1 (revised) into requirement R1 as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated due to a Protection System operation or a Protection System failure to operate

	as designed shall, within 120 calendar days of the BES interrupting device operation, identify whether its Protection System component(s) caused a Misoperation when:” **Response:** The drafting team agrees with your perception of its intent. The posting retained in Requirement R1, Part 1.1 the concept that the interrupting device operations that need to be evaluated were caused by a Protection System. Only interrupting device operations caused by Protection System operations (except those specifically exempted) and manual operations made in response to a Protection failure are within the scope of Requirement R1 in the Standard. No change made.
Tacoma Power	Since Protection System operations that are related to (or caused by, if this verbiage is retained) on-site maintenance, testing, inspection, construction, or commissioning activities are by definition not Misoperations, is it necessary under Requirement R1 to document that the entity identified “whether its Protection System component(s) caused a Misoperation” for these cases of Protection System operations? BES interrupting devices may be operated many times during on-site activities from a Protection System, or part of a Protection System, and it would be very burdensome to document actions taken surrounding this activity for purposes of compliance with PRC-004-3 Requirement R1. Consideration should be given to an additional part under Requirement R1 such as the following: “The BES interrupting device operation was not related to [or caused by, if this verbiage is retained] on-site maintenance, testing, inspection, construction, or commissioning activities.” **Response:** The operation of out-of-service equipment is not applicable to the standard. If the operation of the Protection System causes the operation of an in-service BES Element, it must be evaluated irrespective of on-site activity. Additional information is provided in the Application Guide under Requirement R1 (last paragraph). Change made. Regarding the Severe VSL for Requirement R3, change “...whether or not a Misoperation its...” to “...whether or not a Misoperation of its...” (This also needs to be updated in the VRF/VSL Justification.) **Response:** The language has been changed. Regarding the Moderate VSL for Requirement R5, change the two instances of “...calendar days first...” to “...calendar days of first...” (This also needs to be updated in the VRF/VSL Justification.)

	Response: The language has been changed. On page 32 of the redlined VRF/VSL Justification, in the FERC VRF G3 Discussion, change references to 'VSL' or 'VSLs' to references to 'VRF' or 'VRFs' respectively. **Response:** Change made. On page 39 of the redlined VRF/VSL Justification, in the discussion of FERC VSL G1, change "...being based the..." to "...being based on the..."On page 2 of the redlined Mapping Document, in the Comments column, change "...a review upon a Bulk Electric System (BES) interrupting device operation..." to something like "...a review upon a Bulk Electric System (BES) interrupting device operation initiated by a Protection System and not related to [or caused by, if this verbiage is retained] on-site maintenance, testing, inspection, construction, or commissioning activities..." Explicitly reviewing and (more to the point) documenting each BES interrupting device operation is overly burdensome, as this would include control operations, including those associated with switching, as well as operations caused during on-site activities. **Response:** The comment was intended to provide a discussion of how the requirement in PRC-004-3 is better than the requirement in PRC-003. The text does not convey all the details of PRC-004-3 which include the identification of conditions which are not Misoperations. The drafting team does not believe the addition of the clarification requested is needed to justify for the replacement of PRC-003 requirement R1. No change made. On pages 4 and 19 of the redlined Mapping Document, in the Comments column, change "...a reverse power relay operated to remove a generating unit from service..." to something like "...a reverse power relay operated to remove a generating unit from service as opposed to providing anti-motoring protection..." Whether it is for a protective or control function, the reverse power relay will still remove the generating unit from service; the distinction is why the generating unit is being removed from service. **Response:** The language has been changed. On page 5 of the redlined Mapping Document, in the Comments column, change "...underfrequency load shedding (UFLS)..." to "...underfrequency load shedding (UFLS) that is intended to trip one or more BES Elements..." The Applicability does not include UFLS that trips non-BES Elements (e.g., medium voltage distribution feeders).

	Response: The language has been changed. On page 21 of the redlined Mapping Document, in the Comments column, change “...until is...” to “...until it...” **Response:** The language has been changed.
PPL NERC Registered Affiliates	The expression, “the Misoperation,” in R5 should be changed to, “a determined Misoperation,” in recognition of the fact that some events can be classified only after full investigation, as described above. **Response:** Requirement R5 does not come into the process until the owner of the Protection System component(s) has identified the cause of a Misoperation. Requirement R5 is implicitly pursuant to finding the cause in R1, R3, or R4 as illustrated by: “…first identifying a cause of the Misoperation.” No change made.
Hydro-Québec Production	The purpose of the Standard shall be limited only to "Identify and correct the causes of Protection System Misoperations affecting the reliability of the Bulk Electric System (BES)." The Bulk Electric System (BES) Elements or Protection System Misoperations that may affect the reliability of the Bulk Electric System (BES), shall be first identifed by the PC or RC. **Response:** Using the “affecting the reliability of the BES” has the effect of expanding applicability because all BES Elements are already included. Adding “affecting” would include other Protection Systems. The drafting team contends that the proposed Purpose statement does address Protection Systems that affect the BES. No change made.
Tennessee Valley Authority	The Severity Level wording (re CAP development) is too stringent and very confusing. Adding roughly 5 days (from the timeframe stated in the previous draft) is negligible. The current requirement allows 12 months for CAP development, and changing this to 120 days will not, in some cases, give a utility adequate time to investigate/determine actions going forth. **Response:** CAP development (60 days) is performed after the investigation is complete. It is separate from the "120 day" time period for identifying a Misoperation.

	A CAP is "a list of actions and an associated timetable for implementation to remedy a specific problem." Since CAP's address specific problems, the investigation into what went wrong needs to be completed before a CAP is developed. Per requirement R5, the 60 day CAP development time frame begins once the specific problem that caused a Misoperation is identified. The CAP implementation period is determined by the GO, TO, or DP developing the CAP. No change made.
Public Service Enterprise Group	There is no requirement in the standard for the cause of a Misoperation to be determined by the appropriate Protection System owner. Neither R1 nor R3 obligates the owner to attempt to determine the cause of a Misoperation. We note that R4 presumes the owner could not “determine the cause(s) of a Misoperation in accordance with R1 and R3” when those requirements contain no such obligation. R5 and R6 apply to an owner that has determined the cause(s) of a Misoperation. Therefore, we recommend that R1 and R3 be modified as follows with the following additional capitalized language:”.... shall identify whether its Protection System component(s) caused a Misoperation OR NOT, AND IF SUCH A MISOPERATION OCCURRED, SHALL DETERMINE, IF POSSIBLE, THE CAUSE(S) OF SUCH MISOPERATION. **Response:** Requirements R1 and R3 are for determining whether a Misoperation occurred or not. Requirement R4 is for determining the cause(s), if not determined while performing Requirements R1 or R3. Requirement R4 has been clarified. Change made. “As R1 and R2 are written, one could interpret the language as requiring ALL interruption device operations be evaluated. However, this is not the intent based upon the draft RSAW that’s posted. It states that the evidence required in R1 is “A list of BES interrupting device operations within audit period meeting the criteria of Requirement R1 Parts 1.1 through 1.3.” Therefore, we recommend that R1 and R2 be changed so that it is clear that the only interruption device operations that need to be examined are those that are the unexpected. Expected operations for, as an example, switching would be eliminated from any requirement to review the interrupting device operation. This would greatly simplify the data required to demonstrate compliance. We offer the following additional capitalized language in R1 and R2:”Each Transmission Owner, Generator Owner, and Distribution Provider that owns a BES interrupting device that operated UNEXPECTEDLY shall,....”

	Response: Only BES interrupting device operations caused by a Protection System, a Composite Protection System, or by a manual intervention in response to a Protection System failure need to be investigated. This is stated in Requirements R1.1 and R2.1. No change made.
Exelon	This draft is a significant improvement over the last draft, specifically because of the addition of the "Composite Protection System". We also endorse the use of the rationale boxes within the standard; they lend additional clarity to the requirements of the standard. However, consistent with our comments above, the standard is too prescriptive. For example, there is far too much emphasis on documenting dates. **Response:** The requirements and associated timeframes ensure that the responsible entities are diligent about Misoperation response, CAP creation and completion. The timetables make the requirements measurable. No change made. Additionally, most of the VSL's should be eliminated and labeled "N/A", e.g., on R3, does 30 calendar days really matter? Lower VSL should be up to 60 days late, Moderate is N/A, High is N/A, Severe is more than 60 days late which equals failed to identify. **Response:** The drafting team followed NERC Violation Severity Level Guidelines for VSL escalation. No change made. ComEd also disagrees with the VSL tables because they disproportionately propose to punish a larger utility with more operations (and misoperations). **Response:** The drafting team contends that the VSLs follow the NERC Violation Severity Level Guidelines and do not disproportionately burden a larger utility. The VSLs only apply when an entity fails to comply with the Requirements of the standard. A Misoperation is not a violation of the standard. No change made. There also needs to be a distinction between analyzing automatic operations for misoperations but failing to identify a misoperation in, as an example, 1 out of 100 operations verses taking no effort to identify any misoperations. For these reasons we think the current revision to PRC-004-3 is overly prescriptive and complicated. **Response:** The drafting team contends that each operation of a BES interrupting device according to the requirements is a discrete instance; therefore, a violation would be assessed for not reviewing the

	operation for Misoperation. For example, an entity that failed to review 100 operations would have 100 violations whereas an entity that failed to review one operation would have only one violation. No change made. Suggest that the SDT should evaluate simplifying the Standard to the basic purpose which is to "identify and correct the causes of Misoperation of Protection Systems for BES elements" without introducing hard timelines, overly prescriptive communication requirements, and documentation of the level of corrective actions performed. **Response:** The drafting team contends that the proposed version provides additional clarity over the current version. For example, the proposed version identifies who does what under what circumstances. No change made. Guidelines and Technical Basis: (1) A failure of a Protection System to operate for a Fault within the zone it is designed to protect. Can the drafting team provide an example for generator protection similar to the one provided for the transmission line protection? **Response:** The drafting team added Example 1d to address this concern. Change made. (2) A failure of a Protection System to operate for a non-Fault condition for which the Protection System was intended to operate, such as a power swing, under-voltage, over excitation, or loss of excitation. For example, failure to trip the generator by loss of field protection for a loss of field condition on that generator is a Misoperation. If the generator is tripped by another relay say out of step, should it still be called misoperations? **Response:** Based on the information provided, the drafting team believes that the out-of-step relay is part of the generator's Composite Protection System; therefore, as described in this example the operation is not a Misoperation.
Virginia State Corporation Commisison	Under R5, the owner of a Protection System component that causes a Misoperation shall either develop a CAP or "Explain in a declaration why corrective actions are beyond the entity's control or would not

	improve BES reliability....." I wonder whether the Requirement should identify to whom and by what manner any such "declaration" should be made? **Response:** A declaration is documentation retained by the entity to explain why development of a CAP would not improve reliability and that no further corrective actions will be taken. An entity would have a declaration available to provide to its Regional Entity during a compliance monitoring activity. No change made.
ReliabilityFirst Protection Subcommittee	We believe that the rationale boxes within the standard should be retained to lend additional clarity to the requirements of the standard. **Response:** When this standard has received ballot approval, the rationale boxes are retained and will be moved to the Application Guidelines Section of the Standard. No change made.
Wisconsin Electric Power Company	We strongly believe that the drafting teams need to understand how the standards they are developing will interact with other NERC standards and documents. There may be unintended consequences when the relationships between two standards or other NERC documents are not foreseen. Regrettably, the SDT for the new BES Definition failed to take into account the substantial impact of its product on the various standards that would be applied to the new BES elements. Therefore it is critical for the PRC-004-3 SDT to take a step back and anticipate the effect of the new BES definition on this standard. The case in point is the addition of dispersed generators to the BES. We remain very concerned with the effort that will be required to comply with this standard in light of the new BES facilities that are included in the new BES definition, especially dispersed generation. It is wind that especially troubles us. We have about 200 wind turbine generators in our fleet, all less than 2 MW in size. Wind makes up less than 5 % of our generation capacity. Yet, in terms of the sheer number of generators, the number of wind units is roughly 5 times the number of other larger generators in our fleet. Of these 200 wind generators, 90% will soon become BES generators due to being aggregated in facilities above 75 MVA. It is the outsized impact of these wind turbines that will have a huge effect when we are required to analyze in depth each protection system operation of these wind generators in order to comply with PRC-004-3. This effort will be enormous, and yet the reliability benefit is negligible. The valuable technical resources available at my company, and at

	many other companies with even larger amounts of dispersed generators, are not best utilized by applying this standard at the level of individual wind generators, and other similar small dispersed generators. To allow entities to focus limited technical resources on efforts that truly enhance reliability, the SDT should revise the Applicability to specifically exclude small dispersed generators, and only apply it where the aggregated generation exceeds 75 MVA, that is, to the collector bus and transformer (with the high-side winding operated at or above 100 kv) used to connect to the transmission system. We believe the extra time it takes to think this through will be worthwhile to the industry, and may prevent inadvertent outcomes that may not serve the overall reliability of the bulk power system. **Response:** The Misoperations drafting team understands the concern with the applicability of dispersed generation resources (DGR) to this standard. This drafting team is working with the DGR drafting team addressing standards with this concern under Project 2014-01 – Standards Applicability for Dispersed Generation Resources. In order to keep the sequence of the versions correct, the DGR drafting team will consider the exclusion in this standard once approved by industry. This should not be of great concern due to the implementation time of this standard and the need to bring in alignment with the work of the DGR drafting team. No change at this time.
Seminole Electric Cooperative, Inc.	WECC Extended Implementation Period - The Standard as proposed allows entities in the WECC Region an additional 12-months to comply with the Requirements of PRC-004-3. Seminole requests that entities in all other NERC Regions have the same amount of time to comply. Correlating every Region's effective date to that of WECC would be just, reasonable, and less preferential. **Response:** After further review and discussion with WECC following the latest changes to the standard, the proposed standard and the existing regional standard do not conflict. Therefore, different implementation timeframes are no longer necessary. However, the language used in the implementation plan is the stock language NERC uses for effective dates of Reliability Standards. In the prior version of the implementation, the effective dates were specified separately for WECC to provide time to eliminate language conflicts between the proposed standard and the regional standard. Since no conflict exists, there will be a single effective date for the standard. Change made.

	Evidence Retention - Bullet 2 under section C.1.2. of the Standard deals with evidence retention. Bullet 2 specifically requires retention of evidence 12 months from the date of “completion of each CAP, evaluation, and declaration.” It does not appear that Requirement R5 covers the completion of the CAP; it appears that specific requirement is covered in Requirement R6 and bullet #3 of the evidence retention section. Seminole reasons that the drafting team meant Bullet 2 to state that the retention period is from the date of completion of the “development” of a CAP, not the completion of remedies stated in a CAP. In addition, there are three possible dates for completion of a CAP, evaluation, and declaration. Seminole requests that the drafting team clarify which date, and time period, specific evidence is required. **Response:** Bullet 2 under Section C.1.2 has been redrafted to indicate the data retained should support the development of the CAP in Requirement R5. Change made. When a CAP is developed in accordance with Requirement R5 there will be two dates. One for the completion of the development of the CAP and a second for the completion of an evaluation of the applicability of the CAP at other locations. In the case where a declaration is made that no further corrective actions will be taken, the date will be when the declaration was made. Measure M5 gives examples of acceptable evidence. When a CAP is completed in accordance with Requirement R6 the dates of the completion of actions within the CAP as well as any modifications to the CAP should be retained. Measure M6 gives examples of acceptable evidence.

END OF REPORT