NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Protection System Misoperations – Project 2010-05.1

The Protection System Misoperation Identification and Correction Drafting Team thanks all commenters who submitted comments on the first draft of the standard for Protection System Misoperation Identification and Correction. The standard and associated documents were posted for a 30-day public comment period from June 10, 2011 through July 11, 2011. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 52 sets of comments, including comments from approximately 146 different people from approximately 106 companies, representing 10 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:

http://www.nerc.com/filez/standards/Project2010-05_Protection_System_Misoperations.html

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 Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560, or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received:

The definition of Protection System Misoperation has been modified to reflect comments received. Statements were incorporated into the definition so that only the overall performance of the Protection System is considered when determining a Misoperation. The non-functioning of high-speed Protection Systems required by the performance requirements of the TPL standards has been explicitly incorporated. An additional category of "Slow Trip – Other Than Fault" has been added for consistency. Exclusion of Protection System operations because of on-site maintenance, testing, construction, or commissioning activities has been added due to stakeholder comments. An exclusion to the category "Unnecessary Trip – During Fault" was added related to the proper remote Protection System operation. Comments related to "Fast Trip" were not incorporated because this type of Misoperation is included in the category "Unnecessary Trip – During Fault." Comments related to exclusion of incorrect settings or other design flaws were not incorporated because these fit within one of the established causes of Protection System Misoperation developed by the IEEE Power System Relaying Committee, Working Group I3.

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf.

Some commented on the applicability of the requirements to the Distribution Provider and Generator Owner and the applicability to non-BES Protection Systems, even though the Applicability section specified that the requirements only applied to Protection System(s) of Facilities that are a part of the BES. The standard is applicable to Distribution Providers and Generator Owners and Transmission Owners because these entities can own Protection Systems of Facilities that are a part of the BES.

Some commenters asked why UFLS Misoperations are included in this standard. The drafting team responded that UFLS Misoperations were included because they are not explicitly covered by any existing NERC standards. Sudden Pressure Relay Misoperations are not included because they are not currently part of the Protection System definition.

Many commented that Requirement R1 was too all-encompassing since it was the only requirement in the standard. For example, two very different items, documentation of a process and implementation of the process were in the same requirement. As such, many commenters were concerned that only one VRF existed for the entire standard and the "High" VRF was not indicative of most of the parts contained within Requirement R1. The new draft has separate requirements for the process documentation, the implementation of the process, and other steps in the Misoperation investigation, correction, and reporting. VRFs were established for each of the new requirements.

Numerous commenters were concerned about the 90-day time limit to complete the investigation; including, possibly, taking necessary outages. The SDT revised the standard by increasing the timelines and clarifying the steps involved to complete the investigation of a Misoperation. Allowances for long investigations under an action plan were added. Many commenters were confused about the starting point of the time intervals associated with the Misoperation investigation. The SDT revised the standard to clarify the starting point of the Misoperation investigation (new Requirement R2) is the occurrence of the Protection System operation. Other commenters were concerned about compliance with the timelines in the standard after a natural disaster or significant system event. The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions."

Some commented that reporting Misoperations should be included as a requirement instead of in the Compliance Section. The drafting team consulted with NERC staff and decided that the Compliance Section is the appropriate location for Misoperations reporting. Several commenters proposed to make the Misoperation reporting template the official evidence of compliance. Attachment 1 "Quarterly Misoperations Reporting Data" reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed so as to identify those that are Misoperations. Several commenters had concerns with the reporting form requiring TADS event I.D.'s. The correlation between Protection System Misoperation and TADS events is needed to determine Metric ALR4-1, developed by NERC Operating and Planning Committees under NERC's Rules of Procedure, Section 809. Several commenters pointed out inconsistencies between the new definition

of Misoperation and the categories in Attachment 1. The language in Attachment 1was revised to match the language approved for use in the revised Standard PRC-004. Other inconsistencies will also be resolved. Once the method (website, database, spreadsheets, other forms, etc.) of reporting is established, questions on how to remove previously reported Misoperations that have been determined to not be Misoperations and how to report no additional Misoperations during a reporting quarter will be clarified. One commenter had a concern with quarterly reporting requirements versus, possibly, semi-annual reporting. While some regions require semi-annual reporting today, on October 22, 2010, NERC's ERO Executive Management group endorsed an ERO-RAPA recommendation to the regions to start the collection of data on a quarterly basis beginning in 2011. The 2009 SPCS assessment of PRC-003-1, PRC-004-1, and PRC-016-1 also endorsed quarterly reporting.

Several commenters expressed concern that the use of the word "written" does not allow for electronic data retention. The word "written" has been removed. The measures now provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.

Several commenters expressed concern that the data retention period should not exceed the audit cycle. The Evidence Retention section was redrafted to follow the NERC Rules of Procedure, Appendix 4C, CMEP Section 3.1.4.2, which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.

A few commenters questioned whether Protection System operations occurring during generator synchronization would be covered under PRC-004-3. In the Guidelines and Technical Basis section of the standard, the drafting team explained that these operations are excluded because the generating unit is not synchronized and is isolated from the BES.

Several comments were received on possible conflicts with other NERC standards, Section 215 of the Federal Power Act, and NRC regulations. A review of the issues cited was performed and no conflict is believed to exist.

In response to one comment, the drafting team modified the Background statement to better reflect the interaction between this standard and the WECC regional Misoperations reporting standard. Regional standards for Misoperations reporting can still go beyond what the new NERC PRC-004 will require.

Numerous commenters were concerned about the prescriptive nature of the Guidelines and Technical Basis section of the standard. The SDT clarified that the Guidelines and Technical Basis section of the standard is not mandatory and enforceable and is included to provide insight into the thought processes of the drafting team as they developed the requirements.

One commenter wanted to be exempt from this standard because they are a nuclear generator operator and fall under NRC rules. The NRC rules cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are

applicable to the portions of the nuclear plant related to handling of radiological fuel, security, and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC.

A few commenters expressed concern that the time allowed to develop and implement the required additional processes was too short. The SDT agreed and changed the effective date (implementation time) to 12 months.

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 Reliability Organizations, 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.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	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.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
8.	Mike Garton	Dominion Resources Services, Inc.		5
9.	Brian L.Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
11. Chantel Haswell	FPL Group, Inc.	NPCC 5										
12. David Kiguel	Hydro One Networks Inc.	NPCC 1										
13. Michael R. Lombardi	Northeast Utilities	NPCC 1										
14. Randy MacDonald	New Brunswick Power Transmission	NPCC 9										
15. Bruce Metruck	New York Power Authority	NPCC 6										
16. Lee Pedowicz	Northeast Power Coordinating Council	NPCC 10										
17. Robert Pellegrini	The United Illuminating Company	NPCC 1										
18. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC 1										
19. Saurabh Saksena	National Grid	NPCC 1										
20. Michael Schiavone	National Grid	NPCC 1										
21. Wayne Sipperly	New York Power Authority	NPCC 5										
22. Donald Weaver	New Brunswick System Operator	NPCC 2										
23. Ben Wu	Orange and Rockland Utilities	NPCC 1										
2. Group	John Seelke	Public Service Enterprise Group Company	X		X		X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Ken Brown	PSE&G	RFC	1, 3									
2. Clint Bogan	PSEG Fossil	RFC	5									
3. Peter Dolan	PSEG ER&T	RFC	6									
4. Scott Slickers	PSEG Fossil	NPCC	5									
5. Eric Schmidt	PSEG ER&T	NPCC	6									
6. Mikhail Falkovich	PSEG	ERCOT	5									
3. Group	Sasa Maljukan	Hydro One	X		X							
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Paul DiFilippo	Hydro One	NPCC	1, 3									
2. DAvid Kiguel	Hydro One	NPCC	1, 3									
4. Group	Bill Middaugh	Tri-State Generation and Transmission Ass'n - System Protection	X		X		X					
Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1. Jim Pearsall	Tri-State Generation and Transmission Ass'n.	WECC	1, 3, 5									
2. Gary Preslan	Tri-State Generation and Transmission Ass'n.	WECC	1, 3, 5									

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10
3. Matthew Leyba	Tri-State Generation and Transmission Ass'n.	WECC 1, 3, 5										
4. LeRoy Martinez	Tri-State Generation and Transmission Ass'n.	MRO 1, 3, 5										
5. Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Brian Orians	FE	RFC	5
2. Jim Detweiler	FE	RFC	1
3. Leslie Aleva	FE	RFC	1
4. Robert Loy	FE	RFC	5
5. Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6

6. Group	David Thorne	Pepco Holdings Inc Affiliates	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Alvin Depew	Pepco Holdings Inc	RFC	1, 3
2. Mark Godfrey	Pepco Holdings Inc	RFC	1, 3
3. Carl Kinsley	Pepco Holdings Inc	RFC	1, 3

7. Group	Bill Shultz	Southern Company Generation					X					

Additional Member	Additional Organization	Region	Segment Selection
1. Tom Higgins	Southern Company Generation	SERC	5
2. Terry Crawley	Southern Company Generation	SERC	5
3. Therron Wingard	Southern Company Generation	SERC	5

8. Group	Cynthia S. Bogorad	Transmission Access Policy Study Group	X		X	X	X	X				

No additional members indicated.

9. Group	Jonathan Hayes	SPP Reliability Standards Development Team		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Clem Cassmeyer	Western Famers Electric Cooperative	SPP	1, 3, 5
2. Nick Henry	FERC	NA - Not Applicable	NA
3. Bud Averill	Grand River Dam Authority	SPP	1, 3, 5
4. Louis Guidry	Cleco Power LLC	SPP	1, 3, 5
5. Sean Simpson	McPhearson Board of Public Utilities	SPP	1, 3, 5
6. Shawn Jacobs	Oklahoma Gas & Electric	SPP	1, 3, 5
7. Robert Rhodes	Southwest Power Pool	SPP	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Group	Carol Gerou	MRO's NERC Standards Review Forum										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
12.	Marie Knox	Midwest ISO Inc.	MRO	2
13.	Lee Kittelson	Otter Tail Power Company	MRO	1, 3, 4, 5
14.	Scott Bos	Muscatine Power and Water	MRO	1, 3, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
17.	Richard Burt	Minnkota Power Cooperative, Inc	MRO	1, 3, 5, 6

11.	Group	Connie Lowe	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Crowley		SERC	1, 3, 5, 6
2.	Louis Slade		RFC	5, 6
3.	Michael Gildea		MRO	5
4.	Mike Garton		NPCC	5

12.	Group	Steve AlexandersonPE	Pacific Northwest Small Public Power Utility Comment Group			X	X					X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Russell A. Noble	Cowlitz County PUD No. 1	WECC	3, 4, 5
2.	Dave Proebstel	Clallam County PUD No.1	WECC	3

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
3.	Ronald Sporseen	Blachly-Lane Electric Cooperative	WECC	3										
4.	Ronald Sporseen	Central Electric Cooperative	WECC	3										
5.	Ronald Sporseen	Consumers Power	WECC	1, 3										
6.	Ronald Sporseen	Clearwater Power Company	WECC	3										
7.	Ronald Sporseen	Douglas Electric Cooperative	WECC	3										
8.	Ronald Sporseen	Fall River Rural Electric Cooperative	WECC	3										
9.	Ronald Sporseen	Northern Lights	WECC	3										
10.	Ronald Sporseen	Lane Electric Cooperative	WECC	3										
11.	Ronald Sporseen	Lincoln Electric Cooperative	WECC	3										
12.	Ronald Sporseen	Raft River Rural Electric Cooperative	WECC	3										
13.	Ronald Sporseen	Lost River Electric Cooperative	WECC	3										
14.	Ronald Sporseen	Salmon River Electric Cooperative	WECC	3										
15.	Ronald Sporseen	Umatilla Electric Cooperative	WECC	3										
16.	Ronald Sporseen	Coos-Curry Electric Cooperative	WECC	3										
17.	Ronald Sporseen	West Oregon Electric Cooperative	WECC	3										
18.	Ronald Sporseen	Pacific Northwest Generating Cooperative	WECC	3, 4, 8										
19.	Ronald Sporseen	Power Resources Cooperative	WECC	5										
13.	Group	Brent Ingebrigtson	LG&E and KU Energy		X		X		X	X				
No additional members indicated.														
14.	Group	Jason Marshall	APM Members							X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Johnny York	Brazos Electric Cooperative	ERCOT	1, 3, 5
2.	Mohan Sachdeva	Buckeye Power	RFC	3, 4, 5
3.	Lindsay Shepard	Sunflower Electric Cooperative	SPP	1, 3, 5
4.	Mark Jones	SMECO	RFC	3, 4
5.	Susan Sosbe	Wabash Valley Power Association	RFC	3, 4

15.	Group	Annette Bannon	PPL Generation						X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Don Lock	PPL Brunner Island, LLC	RFC	5
2.		PPL Holtwood, LLC	RFC	5

Group/Individual		Commenter	Organization		Registered Ballot Body Segment									
					1	2	3	4	5	6	7	8	9	10
3.		Lower Mount Bethel Energy, LLC	RFC	5										
4.		PPL Martins Creek, LLC	RFC	5										
5.		PPL Montour, LLC	RFC	5										
6.	Dave Gladey	PPL Susquehanna, LLC	RFC	5										
7.	Leland McMillan	PPL Montana, LLC	WECC	5										
16.	Group	Frank Gaffney	Florida Municipal Power Agency		X		X	X	X	X	X			
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4										
2.	Greg Woessner	Kissimmee Utility Authority	FRCC	3										
3.	Jim Howard	Lakeland Electric	FRCC	3										
4.	Lynne Mila	City of Clewiston	FRCC	3										
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1										
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4										
7.	Randy Hahn	Ocala Electric Utility	FRCC	3										
17.	Group	Chris Higgins	Bonneville Power Adminstration		X		X		X	X				
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1.	John Kerr	BPA, Electrical Engineer, Technical Operations	WECC											
2.	Dean Bender	BPA, Electrical Engineer, SPC Technical Svcs	WECC											
18.	Individual	Brandy A. Dunn	Western Area Power Administration		X									
19.	Individual	Bo Jones	Westar Energy		X		X		X	X				
20.	Individual	Greg Davis	Georgia Transmission Corporation		X									
21.	Individual	Sandra Shaffer	PacifiCorp		X		X		X	X				
22.	Individual	Silvia Parada Mitchell	NextEra Energy, Inc.		X		X		X					
23.	Individual	Antonio Grayson	Southern Company		X		X							
24.	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.				X	X						
25.	Individual	Greg Froehling	Green Country Energy						X					
26.	Individual	Si Truc PHAN	Hydro-Quebec TransÃ‰nergie		X									
27.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP						X					
28.	Individual	Darryl Curtis	Oncor Electric Delivery		X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
29.	Individual	Bob R. Davis	Private Citizen										
30.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
31.	Individual	David Burke	Orange and Rockland Utilities, Inc.	X		X							
32.	Individual	Twila Hofer	PSE	X		X		X					
33.	Individual	Joanna Luong-Tran	TransAlta										
34.	Individual	Ed Davis	Entergy Services	X		X		X	X				
35.	Individual	Dan Hansen	GenOn Energy					X					
36.	Individual	Scott Berry	Indina Municipal Power Agency				X						
37.	Individual	John Bee on behalf of the Exelon Companies	Exelon	X		X		X					
38.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
39.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
40.	Individual	Kirit Shah	Ameren	X		X		X	X				
41.	Individual	Brian Evans-Mongeon	Utility Services, Inc.								X		
42.	Individual	Thad Ness	American Electric Power	X		X		X	X				
43.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
44.	Individual	Armin Klusman	CenterPoint Energy	X									
45.	Individual	Steve Boutilier	BGE	X									
46.	Individual	Eric Salsbury	Consumers Energy			X	X	X					
47.	Individual	Michael Moltane	ITC	X									
48.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
49.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
50.	Individual	Amir Hammad	Constellation Power Generation/Constellation Energy Nuclear Group					X					
51.	Individual	Tracy Richardson	Springfield Utility Board			X							
52.	Individual	Patricia Robertson	BC Hydro	X	X	X		X	X				

1. **The definition of 'Misoperation' has been revised. Do you agree with the proposed definition? If not, please provide specific suggestions for improvement.**

Summary Consideration:

The definition has been modified to reflect comments received.

- Statements were incorporated into the definition so that the overall performance of the Protection System is considered in determining a Misoperation.
- Non-functioning of High-speed Protection Systems required by the performance requirements of the TPL standards has been explicitly incorporated.
- An additional category of "Slow Trip – Other Than Fault" has been added for consistency.
- Exclusion of Protection System operation(s) because of on-site maintenance, testing, construction or commissioning activities has been added.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	1. The new definitions only addressed "Slow Trip". "Fast Trip" could cause misoperation as well. Suggest that the new definition should include "Fast Trip". 2. In the definition of Slow Trip, the word "planned" should be replaced with "designed". Not all faults have characteristics as planned, but fall within a Protection System's designed capability. 3. The "Unnecessary Trip-Other Than Fault" definition as written now would include trips during protection testing and commissioning. Suggest retaining phrase similar to one in current definition: "Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity." 4. It can be said that Protection System Operations for settings that have been miscalculated or applied incorrectly are not Misoperations because the hardware operated correctly. It has to be made clear that even though the hardware might operate correctly, for these situations it does not operate as desired. Terminology that

		has been used for these operations is "correct but undesired". Suggested rewording for "Unnecessary Trip-Other Than Fault": Any Protection System Operation for non-Fault conditions such as power swings, undervoltage, over excitation, or loss of excitation for which the Protection System is not intended to operate. This would also include any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity, or correct but undesired operations because of settings that have been miscalculated or incorrectly applied.

Response: Thank you for your comments.

1. **A "Fast Trip" is not by itself a Misoperation except perhaps when considering the relative operating times of an out-of-zone Protection System to that of an in-zone Protection System. In fact, if the Fault is within the Protection System's zone, a faster than expected operation may be beneficial in reducing the amount of damage or length of the disturbance. The type of Misoperation that you are referring to would most likely be better classified as an "Unnecessary Trip - during Fault." This category covers situations where the out-of-zone backup protection operates faster than the (correctly operating) in-zone primary protection.**

2. **The SDT modified the definition based on your comment. We replaced the word "planned" with "intended". The use of the term "designed" is inappropriate in this case as it could be postulated that a poorly designed system should operate much slower than expected or perhaps not at all.**

3. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**

4. **The SDT disagrees. Protection System operations because of settings that have been miscalculated or incorrectly applied cannot be misconstrued as a "correct" operation when looking at the overall performance of the Protection System. These types of operations are simply incorrect and readily fall into an Unnecessary trip category. It is important to realize that it is the overall Protection System performance being judged and not any individual piece of equipment such as a relay.**

Public Service Enterprise Group Company	Yes	The definition is acceptable provided the clarifications in the "Guidelines and Technical Basis" section of the draft is part of the standard.

Response: Thank you for your comment.

The SDT has incorporated some of the information from the Guidelines and Technical Basis section into the definition. The Guidelines and Technical Basis section will remain part of the standard. This is part of the new Results-based template for Reliability Standards.

Hydro One	No	The fifth category "Unnecessary Trip-Other Than Fault" definition as written now would include trips during protection testing and commissioning. This adds extra work and documentation while adding little value since system operators are aware when such work is going on and thus are prepared for these unnecessary trips. Suggest retaining phrase similar to one in current definition, that is, "... unrelated to on-site maintenance and testing activity".
Response: Thank you for your comment. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Tri-State Generation and Transmission Ass'n - System Protection	No	1. There needs to be a continuation of the specific exclusion for operations that occur as a result of on-site maintenance or testing activity. It seems that the exclusion is intended to remain since there is no "Cause of Misoperation" associated with maintenance or testing. 2. We are not certain how the "Guidelines and Technical Basis" will accompany the new definition in the "NERC Glossary of Terms," but the last sentence in (1) of the Guidelines is not supported by the definition. We disagree that the failure of one high speed Protection System to operate when another does operate should not be classified as a Protection System Misoperation. There may be times when that philosophy is appropriate, but not usually. If the non-operating system can be shown to have simply not had time to operate, then that can be explained in the event report, but typically both high-speed Protection Systems should operate unless one is designed to have a delay. But if it has a delay it shouldn't be classified as high-speed.
Response: Thank you for your comment. **1. The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** **2. The exclusion of this type of failure is based on the NERC SPCS recommendation to consider the composite Protection System of a given Element rather than the individual protective schemes, such as the primary and secondary protection, for an Element.**		
FirstEnergy	No	The last bullet of the current definition includes the phrase "unrelated to on-site maintenance and testing activity". We suggest this be retained in the proposed definition to alleviate any misunderstandings among the responsible entities.

Response: Thank you for your comment. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Pepco Holdings Inc Affiliates	No	1. The original definition excluded protective system operations related to on-site maintenance and testing activities. The new definition does not. A true measure of the performance of a protective system should not include protective system operations caused or initiated by human errors during on-site activities. These include such things as failure to pull appropriate test switches during testing, inadvertently keying a direct transfer trip channel, accidently shorting or bridging a terminal block during construction activities while landing secondary cables, etc. As such, we would propose amending Item 5 of the proposed Misoperation definition as follows: 5. Unnecessary Trip - Other Than Fault - Any Protective System Operation for non-fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protective system is not intended to operate. Unintended Protective System Operations that occur during on-site maintenance, testing, construction, and/or commissioning activities are not considered Protective System Misoperations. (this qualification is consistent with the definition included with the proposed Misoperation reporting spreadsheet and with the intent of the original definition) 2. Also, the qualifying comments in the "Application Guidelines" section associated with the five Categories of Protective System Misoperations should be included, either in the standard itself, or as part of the Misoperation definition. Without these specific qualifications it is not possible to reach a uniform consensus on what constitutes a Misoperation and what does no
Response: Thank you for your comments. **1. The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** **2. Some of the information in the Guidelines has been incorporated in the definition. The Guidelines and Technical Basis section will remain part of the standard. This is part of the new Results-based template for Reliability Standards.**		
Southern Company Generation	No	The proposed definition is excessively lengthy. Items 1, 2, and 3 should be combined into one statement: Any failure of a Protection System to operate for a fault or non-fault condition as it is designed to operate. Items 4 & 5 should be combined into one statement: Any Protection System operation for a fault or non-fault condition when it was not designed to operate. Alternatively, all five statements could be replaced with this one

		statement: A Misoperation is either the operation of a Protection System when it should not have operated or the failure of a Protection System to operate when it should have operated.
Response: Thank you for your comments. **The proposed Misoperation definition is based on the established categories of relay system Misoperation developed by the IEEE Power System Relaying Committee Working Group I3. This definition is also meant to line up with the Misoperation Categories in the reporting form developed by the ERO-RAPA group. A sixth category was added to help clarify what constituted a failure of a Protection System to operate during a non-fault condition since the term "abnormal condition" is ambiguous. By adding this category, the Failure to Trip categories now mirrors the previously established Unnecessary Trip categories. Although it is certainly possible to shorten the definition by concatenating the categories into one or two sentences, it does not actually help in clarifying or correlating the definition to the Misoperation categories.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	1. Would like to add either in this section or in the application guidelines a reference to trips prior to synchronization would not be reported. They would be investigated and corrected but not reported. 2. We are concerned that the definition would lose clarity if the application guidelines are moved out of the standard. If this happens we would like to see some of the meat of the guidelines added to the definition.
Response: Thank you for your comments. **1. The SDT agrees that false trips prior to synchronization should not be reported because the unit is isolated from the rest of the BES. The Guidelines and Technical Basis section has been updated to address your comment. The paragraph reads: "A generator Protection System operation prior to closing the unit breaker(s) is not considered a Misoperation. These types of operations are excluded from review because the generating unit is not synchronized and isolated from the BES. Protection System operations which occur with the protected Element already out of service, that do not trip any in-service Elements cannot be Misoperations."** **2. Some of the information in the Guidelines and Technical Basis will be incorporated in the definition. The Guidelines and Technical Basis section will remain part of the standard. This is part of the new Results-based template for Reliability Standards.**		
MRO's NERC Standards	Yes	

Review Forum		
Electric Market Policy	No	1. Problems with 3. Slow Trip Use of term “slower” in the definition (Page 3 of 16) and “delayed” in the Application Guidelines (Page 12 of 16) is vague. “Slower” seems to indicate an unintentional time period before tripping while “Delayed” implies an intentional time period before tripping. Slow trip definition introduces the term “planned” which adds confusion. 2. Reference to TPL standards implies the need for more and new System Studies. Must these studies be performed and documented prior to installation? What is requirement for keeping these studies current? 3. NERC Glossary definition of Misoperation makes reference to a failure to operate within a specified time for an abnormal condition. There is no mention of “Slow” trip for a non-fault condition in the proposed definition. 4. Only those terms that are in the NERC Glossary should be capitalized. 5. Suggest wording changes as follows: 1. Failure to trip - during Fault - Any failure of a Protection System to operate for a Fault within the zone it is intended to protect. 2. Failure to trip - other than Fault - Any failure of a Protection System to operate for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate. 3. Slow trip - during Fault - Any Protection System operation that is slower than designed for a Fault within the zone it is intended to protect.4. Slow trip - other than Fault - Any Protection System operation that is slower than designed for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which it is intended to operate.5. Unnecessary trip - during Fault - Any Protection System operation for a Fault not within the zone it is intended to protect.6. Unnecessary trip - other than Fault - Any Protection System operation for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate including trips occurring when no disturbance is present. Excludes on-site maintenance and testing.

Response: Thank you for your comments.

1. **The reference to “delayed” clearing in the Application Guidelines refers to specific situations when high-speed clearing is not required to meet TPL standards. However, even if high-speed clearing is not required, the Protection Systems must coordinate between zones to prevent a Misoperation (e.g. an over trip). The SDT has modified the definition of Misoperation based on comments. The word “planned” has been replaced with “intended”. Information in the Guidelines on “Delayed Fault Clearing” has been incorporated in the definition.**

		2. Yes, system studies need to be performed prior to installation of most BES equipment such as a generator to check adequate system performance. The current TPL standards address these studies and their frequency. **3. The SDT added the following language to the definition of Misoperation to address your comment: Slow Trip - Other Than Fault - A Protection System operation that is slower than intended for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System was intended to operate.** **4. Thank you for your remark on capitalization. These words are part of a category header and are capitalized for emphasis.** **5. The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**
Pacific Northwest Small Public Power Utility Comment Group	No	1. The emphasis on the Protection System disregards the effect the breaker might have, since the breaker is not part of the NERC definition of Protection System. The consequences of a slow or failed circuit breaker operation are similar to those of slow or failed protection system operation and should be treated the same. 2. The comment group is concerned regarding the definition of Slow Trip as a "Protection System operation that is slower than planned." How much slower than planned? How do we prove what may have been "planned" many years ago? And even if the settings, documentation, and trip times agree within some not yet defined tolerance; the "plan" itself may be too slow to provide an adequate coordination margin or to prevent instability when relay error, CT error, or subsequent system changes are considered. We propose eliminating the "plan" and looking at the result. We see that Slow Trip is more narrowly defined in the Guidelines and Technical Basis document, but believe this should be extended to the official NERC definition as well. 3. Failure to Trip - During Fault - Any failure of a Protection System or associated protective device to operate for a Fault within the zone it is designed to protect. 2. Failure to Trip - Other Than Fault - Any failure of a Protection System or associated protective device to operate for a non-Fault condition such as power swings, under-voltage, over excitation, or loss of excitation for which the it was intended to operate. 3. Slow Trip - Any Protection System or associated protective device operation that is slower than needed to prevent miscoordination or system instability for a Fault within the zone it is designed to protect.
Response: Thank you for your comments. **1. The definition of Misoperation is only for Protection Systems and the entirety of breakers is not included in the**		

		definition of Protection Systems. This is not meant to minimize the importance of interrupting devices but to narrow the targeted area of review, analysis and corrective actions. **2. The SDT added the following language to the definition of Misoperation to address your comment: Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect. (Delayed Fault Clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems.)** **3. The addition of the words "or associated protective device" to parts of the definition seems unnecessary as the performance of the Protection System is being judged and not that of the current interrupting devices, i.e. breakers, they operate.**
LG&E and KU Energy	No	LG&E and KU Energy believe that further clarity is needed in the definition of Misoperation. Specifically: 1. Item #3 Slow Trip the Standard should specifically exclude those incidents involving slow "total clearing times" that are due to mechanical (or other) problems with the breaker, where all protection system components operated as expected. 2. Item #4 Unnecessary Trip - During Fault. The definition should include unnecessary trips due to improper coordination of relay operating times. (Example: Zone 2 or Zone 3 trip occurring for a fault within its desired reach (zone), but prior to the desired time delay).
Response: Thank you for your comments. **1. It is not necessary to specifically exclude mechanically slow breakers as breakers are not included in the definition of Protection Systems.** **2. The Unnecessary Trip – During Fault category is meant to cover improper coordination and other conditions. Please see the Guidelines and Technical Basis section of the draft standard for examples.**		
APM Members	No	1. It is not clear which definition of Protection System is intended to apply to the definition. Does the current FERC approved definition apply or does the definition approved by the NERC BOT on 11/19/2010 apply. The meaning of Misoperations will be different based on the two definitions. 2. The implementation plan does not make it clear when the new definition will take effect

		and when the old one will be retired.
Response: Thank you for your comments. **1. The current FERC approved definition of Protection Systems is the one applicable to the Misoperation definition. The newer, more detailed definition was approved by FERC in February 2012, and will be effective April 1, 2013.** **2. The new definition of Misoperations will take effect when the Reliability Standard PRC-004-3 is FERC approved.**		
PPL Generation	No	The draft document defines several categories of Misoperation, of which the last is, "Unnecessary Trip - Other Than Fault - Any Protection System operation for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate." The NERC glossary presently states, "Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity." It appears that NERC is dropping the exception for maintenance and test-related relay trips. It would be best to retain the present definition, since such trips usually have little or no bearing on long-term operational reliability.
Response: Thank you for your comment. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Florida Municipal Power Agency	No	We support the use of a Rapid Development Team (RDT) to help speed up the process; however, we only support the RDT drafting the SAR and not the first draft standard. We do not believe an RDT without broad industry representation drafting a standard meets the intent of the Federal Power Act, Section 215 (c)(2)(A) for a "fair stakeholder representation". It is also out of alignment with the Rules of Procedure, Standard Process Manual. And, it is presumptuous to assume that the SAR will not have significant comments that will change the scope and direction of the standard, or that the Standard Development Team, once fully formed, will not scrap the work done by the RDT and start all over again wasting time and effort. As a result, we choose not to comment on the standard, implementation plan, etc., and we only offer comments on the SAR and white paper and highly encourage NERC to reconsider how it deploys RPDs.
Response: Thank you for your comment.		
Bonneville Power Administration	No	1. BPA believes that the new definition does not specify if an inadvertent relay operation due to maintenance or other human activity is a Misoperation. This occurs fairly often,

		and to prevent a lot of confusion, the definition must specify whether or not this is a Misoperation. In the previous definition, this was not a Misoperation, and we would prefer that it also not be a Misoperation in the new definition. 2. Another comment is that the previous definition of a Misoperation is included in the Background section of the draft standard. BPA feels that this is confusing to list this old definition within the standard because it appears that the standard is providing this definition as part of the standard. BPA suggests moving the entire Background section out of the standard.
Response: Thank you for your comments. **1. The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** **2. The SDT is following the current template for a Results-based Reliability Standard which includes a Background section. The SDT believes showing the old definition of Misoperations in the Background section is appropriate.**		
Western Area Power Administration	No	1. The previous "out" for outages which occur during on-site maintenance and testing is missing from the new definition. We would definitely like to see this added. 2. We do like the "Guidelines and Technical Basis" section at the back of the standard which provides some clarification. Hopefully this section gets retained and we agree with most of what is stated, in particular it gives us an "out" for comm-aided protection which is not required by Planning Studies. 3. Misop Category 4 - it is desirable in some cases to "overprotect" or intentionally miscoordinate based on exposure and risk. For example, we tend to allow our Zone 1 elements to cover 85% of our sub transmission lines even though it will miscoordinate with high side tapped transformer protection. This is done so that we will react quickly to the majority of faults which occur mainly on the line. The incidence of high side faults on the tapped transformers is low and we accept the risk of over tripping in those cases. Allowance should be made for entities to intentionally miscoordinate where risk and value make sense. 4. Misop Category 5 - this should actually be strengthened to mention a trip which occurs for non-Fault conditions where the relay or protection system fails. Is this not a Misoperation?
Response: Thank you for your comments. **1. The SDT has modified the definition based on your comment. Language has been added to the proposed definition that**		

reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities." **2. The Guidelines and Technical Basis section is a part of the new template for Results-based Reliability Standards.** **3. In the example provided, the high side of a tapped transformer is most likely within the zone of protection of the line relaying. If so, the line relaying is planned to protect this area and so its operation would not be considered a Misoperation. The SDT will add an example that covers this situation in the Guidelines and Technical Basis section of the draft standard.** **4. The SDT modified the definition of Misoperation based on your comment. The SDT removed the phrase "such as power swings, under-voltage, over excitation or loss of excitation" from the category. There is no need to specifically indicate that a Protection System failure could be the cause for this category as a Protection System failure could cause failure to trips, slow trips and unnecessary trips during Faults.**		
Westar Energy	No	1. "Unnecessary Trip - Other than fault" is not clear if an impedance-based transmission line Protection System trip in response to an unstable (or stable) power swing is a Misoperation. 2. "Failure to trip" as described in the Application Guidelines should have the reference to "within the time normally expected" removed as this would be addressed in "Slow Trip".
Response: Thank you for your comments. **1. A line impedance relay (set as intended) that trips for a power swing that entered the relay's characteristic for its set times is not a Misoperation. If incorrectly set, then it would be a Misoperation.** **2. The phrase "within the time normally expected" is proper as used in the Application Guidelines and is not meant to address the "Slow Trip" categories.**		
Georgia Transmission Corporation	No	1. Failure to operate as designed: a) The protection system failed to operate for a fault within the designated zone of protection. b) The protection system failed to protect a designated BES component from a system abnormality as designed. Operating external to design parameters: a) The protection system operated with no fault condition present. b) The protection system interrupted power to a BES component with no system abnormality present. 2. Slow Trip (as defined) is difficult to measure without "smart relays" or fault recorders or sequence of event recorders in every BES station. A high impedance fault will naturally cause slow clearing times and may indicate an out of zone trip when compared to a bolted fault.

Response: Thank you for your comments. **1. The SDT started with the established categories of relay system misoperation developed by the IEEE Power System Relaying Committee Working Group I3. The "failure to operate" and "operating external to design parameters" categories are already covered under the failure to trip and unnecessary trip categories.** **2. The SDT is neither mandating monitoring tools nor specifying how to investigate BES operations. The standard is being updated to make sure BES operations are analyzed to determine if the Protection System operated as designed and the BES reliability is thus maintained.**		
PacifiCorp	No	The proposal for a revised definition of "Misoperation" in the NERC Glossary of Terms includes five conditions. This definition is insufficient in the absence of considering such conditions in conjunction with the additional illustrative information offered in the "Guidelines and Technical Basis" (the "Guidelines") appended to the draft of PRC-004-3 for industry review and comment. PacifiCorp believes that the proposed revised definition of "Misoperation" should either be: (1) expanded to include additional technical information such as that included in the Guidelines; or (2) revised to expressly provide that the Guidelines, as appended to the standard, are incorporated by reference in the definition. The definition of "Misoperation," if included in the NERC Glossary of Terms as presently proposed is not sufficiently robust for the purpose of registered entities properly identifying and addressing all Protection System Misoperations within their respective systems.
Response: Thank you for your comment. **The SDT has incorporated some of the information from the Guidelines and Technical Basis section into the definition.**		
NextEra Energy, Inc.	No	NextEra Energy suggests modifying "Unnecessary Trip - Other Than Fault" to: Any Protection System operation in the absence of a fault or for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate.
Response: Thank you for your comment. **The category of "Unnecessary Trip - Other Than Fault" has been modified to be more inclusive.**		
Southern Company	No	The definition is acceptable; however, the following recommendations are provided to clarify the Guidelines and Technical Basis for the definition. 1. Failure to Trip - During Fault: The reference to the time in which a Protection System is normally expected to operate introduces aspects of a slow trip into the discussion of failure

		to trip. To avoid confusion between failure to trip and slow trip, the second sentence should be revised as follows: "If a fault or abnormal condition is cleared by at least one Protection System element, then failure of another Protection System element associated with the protection scheme is not a Misoperation." 2. Slow Trip: The TPL standards require that the system is designed to meet performance requirements specified in TPL-001 through TPL-004, but does not require any specific remedy to assure that the requirements are met. Suggest referring to high-speed performance in the context of meeting the performance requirements in place of high-speed performance required by the TPL standards. The sentence should be revised as follows: "Delayed fault clearing caused by a failure of an installed high-speed protection scheme is not a Misoperation if the high speed performance is not required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems." 3. Unnecessary Trip - During Fault: Clarify that while operation of the backup system is not a Misoperation, that failure of the protection for the adjacent zone is a Misoperation. The Note should be revised as follows: "Operation of properly coordinated backup Protection System relays to clear the fault in an adjacent zone is not a Misoperation of that backup system if the protection for the adjacent zone fails to clear the fault within the specified time. However, the failure of the Protection System for the adjacent zone is a Misoperation." 4. Unnecessary Trip - Other Than Fault: The description for this part of the definition lacks clarity as to whether operation of an impedance-based transmission line Protection System in response to a power swing is a Misoperation. The description should be modified to provide clarity on this issue.

Response: Thank you for your comments.

1. Your proposed change to "Failure to Trip - During Fault" in the Guidelines while helping to separate this category from that of "Slow Trip" does not indicate that that the Fault was properly cleared by the combined Protection Systems of the Faulted Element. Your suggestion indicates that the Fault clearing absolves it from being a Misoperation even though it could have been associated with a "Slow Trip" type of Misoperation. The definition of Failure to Trip – During Fault has been enhanced to include reference to overall performance of a Protection System.

2. The definition of Slow Trip was updated to reflect your comments about performance.

3. Your proposed changes to "Unnecessary Trip - During Fault" have been incorporated in the definition.

4. The non-fault conditions listed in this category of the standard has been eliminated. Changes to the Guidelines and Technical Basis section regarding "Unnecessary Trip - Other Than Fault" have been made for clarity. Four examples are

provided in the Guidelines and Technical Basis section including one specifically on power swings.		
Flathead Electric Cooperative, Inc.	No	The definition should be specific to Transmission or BES Misoperations
Response: Thank you for your comment. **Glossary definitions have no assigned applicability. The standard's Applicability (Functional Entities and Facilities) section specifies the applicability to the BES.**		
Green Country Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP believes that that the NERC Glossary definition of Misoperation must coincide exactly with the one used by the ERO-Reliability Assessment and Performance Analysis (RAPA) Group. Although the differences are minor, the two processes need to seamlessly flow together so that data needs and reporting templates do not diverge.
Response: Thank you for your comment. **The work of the RAPA Group on Misoperation reporting was considered as input to the standard drafting effort. The SDT is revising PRC-004-2a; PRC-004-3 will further refine the definition and reporting requirements.**		
Oncor Electric Delivery	Yes	
Private Citizen	No	The definition of a Misoperation no longer includes an exclusion for maintenance activities. Is this intended? While I certainly agree that human errors can cause serious disturbances - for instance the Florida event in 2008 - these events also present lots of challenges to correct. There can be labor issues, disciplinary issues, and a general problem of what CAP to take when the field person says "I knew better. I just screwed up." So, I wanted to know if the drafting team had explicitly considered this topic and chose to include it as a Misoperation going forward.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		

Consolidated Edison Co. of NY, Inc.	No	1. The fifth category "Unnecessary Trip-Other Than Fault" definition as written now would include trips during protection testing and commissioning. This adds extra work and documentation while adding little value since system operators are aware when such work is going on and thus are prepared for these unnecessary trips. Suggest retaining phrase similar to one in current definition, that is, "... unrelated to on-site maintenance and testing activity". 2. The new definition only addressed "Slow Trip". Many times, "Fast Trip" could cause Misoperation as well. We suggest that the new definition should include "Fast Trip".
Response: Thank you for your comments. **1. The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** **2. A "Fast Trip" is not by itself a Misoperation except perhaps when you are considering the relative operating times of an out-of-zone Protection System to that of an in-zone Protection System. In fact, if the Fault is within the Protection System's zone, a faster than expected operation may be beneficial in reducing the amount of damage or length of the disturbance. The type of Misoperation that you are referring to would most likely be better classified as an "Unnecessary trip - during Fault." This category covers situations where the out-of-zone backup protection operates faster than the (correctly operating) in-zone primary protection.**		
Orange and Rockland Utilities, Inc.	No	The new definition only addressed "Slow Trip". Many times, "Fast Trip" could cause Misoperation as well. We suggest that the new definition should include "Fast Trip".
Response: Thank you for your comment. **A "Fast Trip" is not by itself a Misoperation except perhaps when you are considering the relative operating times of an out-of-zone Protection System to that of an in-zone Protection System. In fact, if the Fault is within the Protection System's zone, a faster than expected operation may be beneficial in reducing the amount of damage or length of the disturbance. The type of Misoperation that you are referring to would most likely be better classified as an "Unnecessary trip - during Fault." This category covers situations where the out-of-zone backup protection operates faster than the (correctly operating) in-zone primary protection.**		
PSE	Yes	
TransAlta	No	To add item 6. Unnecessary Trip - Other than Fault - any Protection System Operation for non-fault conditions such as current sensing device failure, voltage sensing device failure,

		DC/AC control circuit/device failure.
Response: Thank you for your comment. **The category "Unnecessary Trip - Other than Fault" already existed and has been modified to incorporate comments received.**		
Entergy Services	No	The definition of Misoperation as proposed in the definition section of the standard needs more detail. In particular, with regard to "Failure to Trip - During Fault", Protection System communication aided schemes which are not essential to meet NERC Planning Standards should be excluded from the definition of Misoperation. An entity that voluntarily exceeds NERC requirements by applying communication aided schemes with more rigor than is required by standards should not be exposed to additional compliance consequences as a result of exceeding those standards. The revised Misoperation definition should specifically include such exception in the actual standard definition and NERC Glossary. In particular, the definition of Misoperation should be changed as follows: Failure to Trip - During Fault - Any failure of a Protection System to operate for a Fault within the zone it is designed to protect. Protection System communication aided schemes which are not essential to meet NERC Planning Standards are excluded from this definition.
Response: Thank you for your comment. **This category of the definition has been modified based on comments received.**		
GenOn Energy	No	1. In the numerous locations used in the definition, replace "Any" with "A" 2. Definition should incorporate the following exclusions: A. Misoperations from human intervention during maintenance activities B. Failure of a relay control function or protective function not associated with protection of the BES or a BES element, i.e. a microprocessor relay serving multiple functions including, but not exclusively, BES Protection. C. Misoperations resulting from the effects of a disaster upon the Protection System components, i.e. a hurricane, tornado, fire, or flood destroys a substation control house.
Response: Thank you for your comments. **1. The SDT modified the definition as you suggested.** **2. A. The SDT has modified the definition based on comments. Language has been added to the proposed definition that**		

reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities." B. The SDT agrees with the comment and modified the language in the Applicability section and Guidelines and Technical Basis section to reflect it. Control functions within relays are not included in the review of Protection System operations for identifying Misoperations. C. The SDT believes you cannot include exclusions for natural disasters in the definition without distorting the intended purpose.		
Indiana Municipal Power Agency	No	1. IMPA has serious concerns that the proposed definition of "Misoperation", including the list of conditions in Draft #1 dated June 9, 2011 (page 12/16) is broad and far reaching and could potentially include equipment not currently defined as Protection System equipment. For example, (3) includes "Any Protection System operation that is slower than planned for a Fault within the zone it is designed to protect" could be interpreted to include high voltage circuit breakers - if a breaker operates (trips) slower than intended (for example in 20 cycles instead of the factory stated 5 cycles) then this could potentially be termed a "Misoperation". By default this would expand the scope of PRC-005 to include additional equipment not currently covered in PRC-005. 2. In addition the Misoperation Categories listed in the drop-down box for Misoperation Category on the Quarterly Misoperation Reporting Form are even less detailed and could be interpreted differently and broader than the proposed definitions themselves. 3. In addition there seems to be an extraordinary amount of effort in PRC-004-3 to lay blame for an operation (now termed "Misoperation") on operating/maintenance/engineering personnel leaving the reporting utility open for damages because of "errors". Utilities have and always will use good faith efforts and follow prudent utility practices when operating their utility. The goal of any utility is to minimize outages/customer interruptions - with PRC-004-3 we are now opening ourselves up to fines for lack of compliance and potential lawsuits should personnel "miss" a setting. Additional causes listed include in the definitions tab on the spreadsheet include, for instance, under Communications failures, Telco errors resulting in the mal-performance of communications over leased lines. Once a leased line leaves the utility's premises they have NO control over that circuit - it is the property of the Telco. If a TELCO technician lifts a bridge clip at a CO on a protection circuit then the utility could potentially be held responsible for a Misoperation. IMPA had no objections with the current definition of Misoperation and feels the proposed definition should stay consistent with current definition.
Response: Thank you for your comments.		

1. Incorrect functioning of equipment not included in the Protection System definition (e.g. breakers) does not fit into the classification of a Misoperation. **2. The Misoperation Categories listed in the drop-down box for Misoperation Category on the Quarterly Misoperation Reporting Form are titles that are defined in the definition.** **3. The purpose of the standard is not to blame individuals for Misoperations but to set up requirements to identify and correct the causes of Misoperations in order to improve the reliability of the BES. It would be negligent of the industry to ignore the human factor as a contributor. In the example of a telecommunication company (TELCO) error causing a Misoperation, the electric utility is responsible for identifying that the Misoperation was due to a TELCO problem, follow up with TELCO to ensure the problem is fixed, consider whether any other corrective actions need to be taken and implement the corrective actions if applicable.**		
Exelon	Yes	1. The definitions are fairly generic but there are additional qualifications in the Application Guidelines. See #3 Slow Trip definitions versus Application Guidelines # 3, this could lead to inconsistent applications. 2. ComEd: Suggest including language regarding human performance events. Is the intent of bullet #5, on page 3, to excluded human performance events as with the previous definition?
Response: Thank you for your comments. **1. The SDT has incorporated some of the information from the Guidelines and Technical Basis section into the definition.** **2. The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Manitoba Hydro	No	Item 3 (Slow Trip) in the definition of 'Misoperation' should be clarified by replacing the word 'planned' with 'specified'.
Response: Thank you for your comment. **The SDT replaced the word "planned" with "intended" based on other comments.**		
Tacoma Power	Yes	Yes, the proposed definition is reasonable, provided that protection system operations resulting from maintenance, testing, or similar inadvertent activities are excluded, as is the case with the existing definition. Alternatively, the proposed definition is reasonable if under R1.3, "a declaration explaining why there is no need to develop a CAP" is

		acceptable.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Ameren	No	Please 1) show the present Misoperation definition so that entities can see how much SDT is proposing to change it. 2) The entire 3rd bullet item (excluding on-site maintenance caused) of the existing definition needs to be retained in your proposed definition items 2 and 5; 3) clarify in item 3 'Slow Trip' by adding 'slower than required to meet TPL requirements' as the SPCS intended; 4) explain in the Background section that "a Protection System" is an element's protection in its entirety (e.g. for a transmission line, it would typically consist of both the primary and secondary protection designed to protect the line) and provide such an example; and, 5) remove 'power swings' from items 2 and 5 'Other Than Fault' examples because it is pre-mature to include until after protective relay response during power swings is addressed in Phase 3 of Project 2010-13.
Response: Thank you for your comments. **1. The existing definition is listed in the Background section. The definition was extensively rewritten; so, a red-lined version would be confusing.** **2. The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."** **3. The reference to "delayed" clearing in the Application Guidelines refers to specific situations when high-speed clearing is not required to meet TPL standards. However, even if high-speed clearing is not required, the Protection Systems must coordinate between zones to prevent a Misoperation (e.g. an over trip). The SDT has modified the definition of Misoperation based on comments. The word "planned" has been replaced with "intended". Information in the Guidelines on "Delayed Fault Clearing" has been incorporated in the definition.** **4. The definition of Misoperation has been modified and addresses your concern.** **5. The project referenced addresses loadability of relays during stable power swings. The SDT agrees that "power swings" does not need to be mentioned in category 5 (now category 6); however, it should remain in category 2. For example, if a power swing enters an impedance characteristic of a relay that is intended to trip for such a power swing,**		

its failure to operate would be a Misoperation.		
Utility Services, Inc.	No	Utility Services disagrees with the addition of incorrect settings to the definition of a Misoperation (Cause Code in Table 2 of the White Paper). Misoperations imply that there was an action or inaction based upon the equipment not performing. It is our view that incorrect settings are maintenance and testing function, not a Misoperation. Utility Services is NOT suggesting that we ignore incorrect settings of these devices. I believe that incorrect settings should be dealt with in the PRC-005 standard instead. As a part of regular maintenance and or testing, the settings should be validated and affirmed by the entity. A Misoperation is when a device fails to act or acts inappropriately. Finding out at the time of the Misoperation that the settings are incorrect are not the right time to determine this. The better standard of reliability for these devices is to do it before they misoperated. If the M&T routines are validating the settings on a regular basis, then the discovery/re-correction will actually benefit reliability because they will be corrected prior to any so-called Misoperation.
Response: Thank you for your comment. **An incorrect relay setting can be the cause of a Misoperation and should be corrected whenever found. Incorrect settings are not always found by the maintenance and testing function; for example, if a setting was incorrectly calculated, the error would most likely not be discovered by maintenance and testing.**		
American Electric Power	No	It would appear that the proposed definition is overly broad, when compared to the application guidelines specified on page 12. For example, going strictly by the criteria on page 3, one might unnecessarily report a Misoperation when it would not be considered such according to the guidelines. Employee action, during on-site maintenance and testing or commissioning activities, that directly initiates an unintentional operation should not be included in this category. However, for example, if an employee leaves trip test switches or cut-off switches in an inappropriate position following maintenance and testing or commissioning activities and a system fault or condition causes a Misoperation, this would be counted as a Misoperation.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
American Transmission Company, LLC	No	The definition of Unnecessary Trip - During Fault should be changed to "Any Protection System operation that causes a circuit breaker/switcher to trip for a Fault not within the

		zone it is designed to protect." The definition for Unnecessary Trip - Other Than Fault should be changed to "Any Protection System operation that causes a circuit breaker/switcher to trip for non-Fault conditions such as power swings, under-voltage, over excitation, or loss of excitation for which the Protection System is not intended to operate."
Response: Thank you for your comment. **The proposed definition was meant to generalize the operation function. The SDT believes the Misoperation categories "Unnecessary Trip" implies that an interrupting device has operated.**		
CenterPoint Energy	No	The proposed revision to the definition of Misoperation includes conditions that are found in the Guidelines and Technical Basis in PRC-004-3, but not in the definition itself. CenterPoint Energy recommends that the conditions be included in the formal definition, instead of in a separate document. Should this recommendation not be accepted, as an alternative, the following statement should be added to each of the five items in the definition of Misoperation: "For specific conditions, refer to the Guidelines and Technical Basis in PRC-004-3 Reliability Standard."
Response: Thank you for your comment. **The SDT has incorporated some of the information from the Guidelines and Technical Basis section into the definition.**		
BGE	No	Item #5 Unnecessary Trip - Other than Fault The Misoperation definition included in the Misoperation reporting template includes the caveat "an operation that occurs during on-site maintenance, testing, construction and/or commissioning activities is not a reportable Misoperation. This should be carried through the definition as well.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Consumers Energy	No	This definition is much better than the current definition. However, the Unnecessary Trip - Other Than Fault should specifically exclude operations during on-site activities.
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads**		

"and is unrelated to on-site maintenance, testing, construction or commissioning activities."		
ITC	Yes	
Wisconsin Electric	No	The 5th category, "Unnecessary Trip - Other Than Fault", should also include an exception for trips which occur during onsite testing or maintenance work on the associated protection system. This exception is in the existing definition, and we maintain it should remain in the new definition. This is needed to allow exceptions for trips which may occur during commissioning or when making modifications due to the complexity of modern protection and control schemes.
Response: Thank you for your comment. **The SDT has modified the definition based on your comment. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Duke Energy	No	1. On #2 "Failure to Trip - Other Than Fault", need to add the word "abnormal" before the word "non-Fault" in order to exclude normal non-Fault situations such as where protective relays are used for control functions (i.e. reverse power relays on generators). 2. On #4 "Unnecessary Trip - During Fault", need to replace the phrase "not within the zone it is designed to protect" with the phrase "for which the Protection System is not intended to operate". The current wording would not require reporting of unnecessary trips for a fault within the zone the Protection System is designed to protect. For example, we use over-reaching protection for breaker failure protection. 3. On #5 "Unnecessary Trip - Other Than Fault", it should be made clear where failed relays would be reported. For clarity, add the phrase "or any other normal system condition" after the phrase "loss of excitation".
Response: Thank you for your comments. **1. The SDT disagrees with the comment as abnormal in this case is a subjective term. Verbiage has been added to the "Guidelines and Technical Basis" section to provide clarity on the issue and to exempt control function operations from being classified as a Misoperation (whether or not the control function is performed within a protective relay).** **2. The SDT has modified the definition, as you suggested.** **3. The SDT modified the definition of Misoperation. The SDT removed the phrase "such as power swings, under-voltage, over excitation or loss of excitation" from the category. There is no need to specifically indicate that a Protection**		

System failure could be the cause for this category as a Protection System failure could cause failure to trips, slow trips and unnecessary trips during Faults.		
Constellation Power Generation/Constellation Energy Nuclear Group	No	The definition language is not clear on failures due to human intervention. For example when TO testing in a switchyard causes a GO trip, is that a Misoperation?
Response: Thank you for your comment. **The SDT has modified the definition based on comments. Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities."**		
Springfield Utility Board		
BC Hydro	Yes	

- An exclusion to the category "Unnecessary Trip – During Fault" was added to the definition related to the proper remote Protection System operation.
- Comments related to "Fast Trip" were not incorporated because the SDT believes that this type of Misoperation is included in the category "Unnecessary Trip – During Fault".
- Comments related to exclusion of incorrect settings or other design flaws not being a Misoperation were not incorporated because these fit within one of the established causes of relay system Misoperation developed by the IEEE Power System Relaying Committee Working Group I3.
- Comments related to inclusion of the entirety of breakers within the reporting of Misoperations were not included because the mechanical portion of a breaker is not part of a Protection System.

2. In Requirement R1.1, the team is requiring the identification of all Misoperations. Do you agree that Requirement R1.1 is sufficient to identify Misoperations? If not, please provide specific suggestions for improvement.

Summary Consideration:

The principle comments covered:

- The ambiguity concerning the scope of Misoperations. The SDT modified the requirements and clarified that Misoperations were limited to those components of Protection System(s) owned by the entity.
- The entire scope of Protection System operations need to be reviewed to determine if a Misoperation has occurred. The SDT clarified that review of Protection System operations was not associated with control functions of relays. The SDT also clarified that the classification of Protection System operations as a Misoperation does not include the individual components of the Protection System, if the Protection System, as a whole, operated correctly.
- The applicability of the requirements to the Distribution Provider and Generator Owner and the applicability of Protection Systems, whether BES or non-BES. The SDT referenced the Applicability section which specified the entities to which the requirements applied, and that the requirements only applied to Protection System(s) of Facilities that are a part of the BES.
- Concerns about the Misoperations procedure and its implementation. The requirement to have and implement a procedure has been eliminated.
- The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 “Compliance Monitoring and Assessment Processes” of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	Yes	This item refers to Part 1.1.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment.		
Public Service Enterprise Group Company	Yes	
Hydro One	Yes	
Tri-State Generation and Transmission Ass'n - System Protection	No	The term "detailed" is too vague and should be eliminated. See comments to the "Measures."
Response: Thank you for your comments. **The SDT agrees and has removed the word "detailed" from the standard. See the SDT response to your comments regarding Measures in Question 5.**		
FirstEnergy	No	1. We do not believe that 1.1.1 (Document and review all BES Faults and BES Protection System operations.) should apply to GO as written, even though R1 indicates it would. We realize that the Glossary definition of BES includes generation resources, but as 1.1.1 is written, it implies that it's referring to the transmission system. 2. Regarding the phrase "within its system" at the end of R1, we ask that this be clarified by changing the phrase to "within its area of ownership or control". 3. We ask that the requirements to "have" and "implement" a Misoperations procedure be separated. We suggest removing the word "implement" from R1 and creating a separate R2. 4. Furthermore, see our answer to Question 4 regarding VRF.
Response: Thank you for your comments. **1. Part 1.1.1 has been deleted and Requirements revised to remove the ambiguity relating to applicability to Generator Owners. The text in the requirements now refers to the Misoperations of the entity's Protection System(s).** **2. The phrase "within its area of ownership or control" of the Protection System could introduce an inadvertent reliability gap such as when instrument transformer windings are shared. By modifying the text as requested the team is concerned that the owner of the instrument transformer will expect the owner of the relay fed by the instrument**		

Organization	Yes or No	Question 2 Comment
transformer to provide the appropriate documentation. The application of the standard is by default limited to the Protection System(s) owned by the entity. The text has been revised to refer to the Misoperations of the entity's Protection System(s). **3. The standard has been revised to state what an entity must do to find and resolve Misoperations. The requirement to have and implement a procedure has been eliminated.** **4. See our response in Question 4.**		
Pepco Holdings Inc Affiliates	No	Requirement R1 should be modified to read "Each Transmission Owner, Generation Owner, and Distribution Provider shall have and implement a procedure to identify and address all BES Protective System Misoperations within its system." The term BES was omitted from R1. We feel the term BES should appear in both R1, as well as R1.1.1, since this requirement is applicable only to protective systems associated with the BES.
Response: Thank you for your comment. **The standard has been revised to eliminate the use of the term 'BES' in the requirements. BES is mentioned in the Applicability section of the Standard.**		
Southern Company Generation	No	We believe that too many details are included in the existing Requirement R1. It is not necessary to be so specific on the documentation process. A high level requirement is much more appropriate. With so many details regarding the investigation compositional elements, valuable attention to resolving the operation/mis-operation is diverted to record keeping. Keep in mind that a large utility may have several relay operations per week, and requiring specific time tabling for each requirement with varying start dates for the magnitude of relay operations makes the proposed approach quite burdensome. It is not necessary to have a written relay operation investigation methodology in order to investigate all relay operation. Requiring a program document is not an essential component of reviewing operations and executing corrective action if they are needed. Please consider changing the existing lengthy requirement that, in our opinion, has far too many detailed requirements with the following three requirements which match the objectives of the current draft on page 5 of the PRC-004-3 draft standard dated 09 Jun 2011 (Draft #1). R1: Review all Protection System operations on the BES and identify those that are BES Protection System Misoperations. R2: Analyze BES Protection System Misoperations to determine the cause(s). R3: Where appropriate, implement Corrective Action Plans to address the cause(s) of the BES Protection System Misoperation. The

Organization	Yes or No	Question 2 Comment
		requirements do not need to be any more complicated that these. The accompanying measures to match these requirements can be: M1: Documentation proving that all (BES Protection System) operations were reviewed. M2: Documentation of analyses to determine cause(s) of the mis-operation. M3: Documentation of all Corrective Action Plans (problem resolution) resulting from misoperations. Revising the requirements to match the objectives listed provides an effective, simply stated standard for identifying and correcting Protection System Misoperations.
Response: Thank you for your comments. **The details in the requirements are needed to ensure they are measureable and enforceable. The requirements have been revised to ensure only the necessary detail is included.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	1. Want to be clear that the wording in R1 and in section R1.1.2 refer to the BES and not all Misoperations. 1. 2. Would like to see BES included in R1 between address all BES protection system Misoperations. Also would like BES added to Section 1.1.2 for clarity. 2. 3. We would ask that this requirement be broken up to address identification, corrective action, and reporting. This would give you greater flexibility to create different VRF and VSLs for each piece that is being addressed. 3. 4. We feel that making an administrative action, such as completing a report, a high on the VRFs and VSLs isn't justified.
Response: Thank you for your comments. 1. The language in the requirements has been revised to refer to the Misoperations of the entity's Protection System. 2. The Applicability Section specifically states, "Protection Systems for Facilities that are part of the BES." 3. The standard has been revised to separate these items into different requirements. The SDT explored using either a standard		

Organization	Yes or No	Question 2 Comment
requirement or a Section 1600 data request for Misoperation(s) reporting. At this time, the SDT feels the appropriate place in the standard for Misoperation(s) reporting is section 1.4 Additional Compliance Information. 4. The Violation Risk Factors have been revised.		
MRO's NERC Standards Review Forum	No	1. This requirement is overly prescriptive and unnecessary. The requirements (and its parts) should not prescribe how entities should comply, but address the "what" is to be accomplished within this requirement. NERC Reliability Standards should specify simple actions such as: 1) that the applicable entities should have a procedure for identifying all BES protection system misoperation on BES protection systems installed for detecting faults on BES elements, 2) implement corrective actions for identified systemic causes of BES protection system Misoperations, 3) document those actions, and 4) report all BES Misoperations to their regional entity on a quarterly basis. This is a better way to meet the goal to require the identification of all BES protection systems installed for detecting faults on BES elements. Simply have a plan, implement the plan when warranted, document what the entity accomplished and report quarterly to the applicable Region. The misoperation report could also be used by NERC and the applicable Region for trending of Misoperations. 2. It is recommended that the SDT align this project with the NERC Functional model. 3. The reference to its system implies operations when it's more like the equipment it owns, please clarify. 4. R1 also uses the word "all" with Protection System Misoperations. Since the SDT has defined 5 different attributes of what a Misoperation is, this would require every function of a relay to have 5 areas that "identify and address" the associated Misoperation. If an entity's relay has 15 functions associated with it, they will need to identify up to 75 ways of identifying and addressing the Misoperation. Note that Protection System is clearly defined and has 5 components to it. So the 75 ways to identify and address the Misoperation will also need 4 more (not five since relays are used as the example). 5. Recommend that the SDT rewrite R1 to read: Each TO, GO, and DP shall have and implement when required, a procedure to identify and address the Misoperation of a BES Protection System within its metered boundaries. 6. Recommend that the SDT add a requirement 2 that fulfils the section 1.4 additional compliance information concerning quarterly reporting.

Organization	Yes or No	Question 2 Comment
		7. Requirement 1.1.1 should be for BES Protection System Misoperations not all operations. The use of the word "all" BES Protection System operations seems unreasonable and un-necessary. Exceptions need to be allowed e.g., acts of god, storms, etc. This requirement is overly burdensome for those individuals involved in restoration. (Certain relays lose information once they are reset.) The NSRF recommends that that this requirement be removed altogether unless further clarified.
Response: Thank you for your comments. 1. The SDT has modified the standard to reduce the detail of the documented process for all processes associated with Misoperations. 2. It is not clear from your comment what aspect of the standard fails to be aligned with the NERC Functional Model. 3. The language in the requirements has been modified to refer to the Misoperations of the entity's Protection System. 4. The definition has been revised to address your comment. The phrase, "Failure of a Protection System to operate as intended," was added. 5. The standard has been revised to separate the documented process and the implementation of the process. In reference to the "when required" action, specific time frames are necessary to ensure a measureable and enforceable requirement. The language in the requirements has been revised to refer to the Misoperations of the entity's Protection System. 6. The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information". 7. The SDT has modified the standard to require the Registered Entity to develop a process that ensures each operation of its Protection System(s) is reviewed for Misoperations. To determine all Misoperations, all Protection System operations must be reviewed with a systematic approach. The Guidelines and Technical Basis section of the standard includes the following statement regarding extenuating circumstances: "In the event of a natural disaster, note that the Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions in relation to the timelines outlined in this standard."		
Electric Market Policy	Yes	1. Dominion suggests R1 to read "Each Transmission Owner, Generator Owner, and Distribution Provider shall have and implement a procedure to identify and address all BES Protection System Misoperations within its system." While the purpose statement

Organization	Yes or No	Question 2 Comment
		indicates that is the intent of the standard, we believe the inclusion of BES in the first sentence of R1 will avoid questions as to whether this standard applies to ALL Protection System Misoperations (including those that are not designed to protect the BES). 2. Recommend changing (R.1.1.1) to state "Document and review all BES Faults and BES Element operations. (R1.) Lists in the requirement that entities must identify and address all Protection System Misoperations. To do this you must either have a Fault or Element to operate to initiate the process. 3. Having the Violation Risk Factor listed in the brackets under (R1.) only adds confusion to the Requirement. In (R1.), only list those specific items that are required according to the new standard and remove the reference to the Violation Risk Factor. The VRF and VSL information should be in a separate dedicated section and not in the requirement section.
Response: Thank you for your comments. **1. The language of the requirement has been revised. The Applicability section specifically limits facilities to the Protection Systems of BES facilities.** **2. The Misoperations of the Protection System may be the result of faults on a Facility other than a BES facility. The SDT has modified the standard to require the Registered Entity to ensure each operation of its Protection System(s) is reviewed for Misoperations.** **3. This is the standard NERC format for Reliability Standards. The VRFs and VSLs are also provided in a separate section of the Reliability Standard named 'Table of Compliance Elements'.**		
Pacific Northwest Small Public Power Utility Comment Group	No	1. Please see our answer to Q1. 2. Slow tripping events that went according to "plan" are not identified as Misoperations even though the result may not have been intended. 3. Slow or failed breaker operations are also not identified as Misoperations.
Response: Thank you for your comments. 1. **The definition of Misoperation is only for Protection Systems; the entirety of breakers is not included in the definition of Protection Systems. This is not meant to minimize the importance of interrupting devices, but to narrow the targeted area of review, analysis, and corrective actions.**		

Organization	Yes or No	Question 2 Comment
2. **The SDT added the following language to the definition of Misoperation to address your comment: "Slow Trip - During Fault - A Protection System operation that is slower than intended for a Fault within the zone it is designed to protect." Delayed Fault clearing associated with an installed high-speed protection scheme is a Misoperation if the high-speed performance is required to meet the performance requirements of the TPL standards or by coordination requirements with other Protection Systems.** 3. **The entirety of a breaker is not considered a part of a Protection System. Please see the Guidelines and Technical Basis section.**		
LG&E and KU Energy	No	1. Much more than Misoperations is required in R1.1.1. A) The GO/DP would not have knowledge of BES faults outside the boundaries of GO or DP, and this requirement should only involve the TO; B) Reporting correctly operating equipment will not increase the reliability of the BES system. 2. Any operator-initiated action or normal/expected operation of relays should not require documentation when the goal of this standard appears to be about "Misoperations". Having to document/investigate correct operation will delay performing required actions to bring a unit on-line to support the BES system.
Response: Thank you for your comments. 1. **A) The SDT has modified R1 to require the Registered Entity to ensure each operation of its Protection System(s) is reviewed for Misoperations.** **B) While Entities are not required to report correct operations, it is understood that the Entities need to have evidence that each Protection System operation has been reviewed.** 2. **The requirement language has been revised. The Standard has been revised to require review of each Protection System operation. There is no requirement to document operator-initiated actions in this standard.**		
APM Members	No	1. While R1 is sufficient to identify Misoperations, there are several issues with the requirements. In R1, use of Protection System as a description with Misoperations is redundant. The proposed definition of Misoperations includes Protection System. 2. While we understand Part 4.2.1 of the Applicability section limits the applicability of the standard to Facilities that are part of the BES, we are concerned that the applicability section could be overlooked. Thus, we suggest the language ("Distribution Provider that owns a BES Protection System") from the previous version of the standard be

Organization	Yes or No	Question 2 Comment
		incorporated into the requirements. 3. The language of the "within its system" should be replaced with "on its equipment". The Generation Owner, Transmission Owner and Distribution Providers don't have systems in the traditional sense. They own parts of the System. "On its equipment" should be appended to the end of Part 1.1.1. Otherwise, the part could be inadvertently interpreted as applying to every BES Fault and BES Protection System regardless of equipment ownership. For example, TO A might have to evaluate a Fault on TO B's equipment. Clearly, this is not the intent. 4. The second bullet under Part 1.2 and the bullet under Part 1.4 are redundant. Both require the registered entity to identify additional steps for an investigation.
Response: Thank you for your comments. 1. **Since the term "Misoperations" is defined as applicable to a Protection System, which is also a defined term, the language has been revised to remove the term Protection System in front of Misoperations.** 2. **The Applicability Section is a formal part of the Reliability Standard. Adding the additional statement would create redundancy.** 3. **The text has been revised to refer to the Misoperations of the entity's Protection System.** 4. **The standard has been revised.**		
PPL Generation		
Florida Municipal Power Agency	No	see comments to Question 1
Bonneville Power Administration	No	1. BPA feels that R1.1 is ambiguous. 2. In R1.1.1, what does it mean to document and review a BES fault? 3. In R1.1.2, identify and document all Misoperations associated to what? 4. In R1.1.3, BPA believes the word "address" is ambiguous.
Response: Thank you for your comments.		

Organization	Yes or No	Question 2 Comment
1. The standard has been revised in an attempt to remove ambiguity. **2. The reference to BES Faults has been removed.** **3. The standard has been revised. Misoperations are associated with an entity's Protection System operations.** **4. The word "address" is no longer used.**		
Western Area Power Administration	Yes	
Westar Energy	No	The requirement should be specific to BES Misoperations.
Response: Thank you for your comment. **The term Misoperations only applies to Protection Systems which are limited in the Applicability section of the standard to 'Protection Systems for Facilities that are a part of the BES'.**		
Georgia Transmission Corporation	No	R.1.1.2 is extraneous. If R1.1.1 is adhered to, all Misoperations will be identified and documented.
Response: Thank you for your comment. **The standard has been revised.**		
PacifiCorp	Yes	
NextEra Energy, Inc.	Yes	
Southern Company	Yes	
Flathead Electric Cooperative, Inc.	No	1.1.2 & 3 should be specific to BES Misoperations
Response: Thank you for your comment. **The term Misoperations only applies to Protection Systems which are limited in the Applicability section of the standard to**		

Organization	Yes or No	Question 2 Comment
'Protection Systems for Facilities that are a part of the BES'.		
Green Country Energy	No	1. My concerns surround sub requirement 1.1 and 1.1.1. First concern is 1.1 the word detailed is too subjective of a term to be audited in my opinion. I would suggest replacing it with "step by step". 2. Second concern is 1.1.1 "Document and review "all" BES Faults and BES Protection System operations."It does not address that protection system operations occur daily in a cycling combined cycle possibly other generation plants too. As an example the steam turbine is brought offline using the reverse power relay. That is a BES protection system operation. I would suggest language that allows documentation of expected "normal operations" and secondly exempting those expected operations from the "document and review" requirement.
Response: Thank you for your comments. **1. The standard has been revised. The word "detailed" is no longer used.** **2. If the reverse power relay is used exclusively for control then it is not considered part of the Protection System. If the reverse power relay doubles for protection and control, review of the relay operation would be necessary when an unexpected operation occurs.**		
Hydro-Quebec TransEnergie	Yes	
Ingleside Cogeneration LP	No	There needs to be a tight correlation with the Misoperation cause codes already introduced in the RAPA reporting template. Since those codes are already acceptable to NERC, it provides a technically sound starting point for a Misoperation investigation. If the RAPA team accumulates enough data to justify another cause code or provide further examples, than they can control it at one place. Ingleside Cogeneration believes that this is the only way that reporting needs can be managed properly. If guidance is not provided in PRC-004-3, then regional differences will continue to crop up - with unique data requirements and reporting templates.
Response: Thank you for your comments. **The SDT has been coordinating with the ERO-RAPA group. The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was**		

Organization	Yes or No	Question 2 Comment
appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".		
Oncor Electric Delivery	Yes	
Private Citizen	No	In R1.1.1, the drafting team calls for all BES faults and operations to be documented and reviewed. Why? Presumably, the drafting team is concerned that Misoperations can go undetected and that the opportunity to learn from - and avoid that SECOND Misoperation - would be lost. However, in the Guidelines and Technical Basis found on page 12 of 16, the drafting team proceeds to define certain protection system "failures" (my term) as not being a Misoperation. For instance, the failure of a redundant Protection System when another Protection System operates correctly or the failure of a communication scheme when TPL standards were not violated. Conceptually, this makes no sense. Either you are worried about undetected Misoperations or you are not. But you cannot have it both ways. Imho (in my honest opinion, so my grand kids tell me, you should write the investigation requirements like this. One must investigate to see if a Misoperation occurred when: a) the operation of any current interrupting device (i.e. breaker) by relay action for a fault not in its primary zone of protection, b) the operation of any circuit interrupting device by relay action when no fault occurred, c) when equipment damage due to a fault condition occurs but no Protection System operated. The wording can be improved, but I believe you can get the idea. If the drafting team believes it must have all operations analyzed, then it must remove the exemptions in the Guidelines and Technical Basis, as these are inconsistent with analyzing all operations for Misoperations.
Response: Thank you for your comment. **The standard has been revised; the reference to Faults has been removed. The SDT believes a review of all Protection System operations is necessary to determine Misoperations. The Guidelines and Technical Basis section of the standard has been modified to be more aligned with the definition of Misoperation. The revised definition is consistent with the NERC System Protection and Control Subcommittee proposed definition of Misoperation.**		
Consolidated Edison Co. of	Yes	By selecting "Yes", we assume "R1" mentioned here is really "R1.1".

Organization	Yes or No	Question 2 Comment
NY, Inc.		
Response: Thank you for your comment about the typographical errors on the comment form.		
Orange and Rockland Utilities, Inc.	Yes	By selecting "Yes", we assume "R1" mentioned here is really "R1.1".
Response: Thank you for your comment about the typographical errors on the comment form.		
PSE	Yes	
TransAlta	Yes	
Entergy Services	Yes	
GenOn Energy		
Indiana Municipal Power Agency	No	In its current proposed format R1 requires that ALL operations have to be reviewed and documented for determination of a possible "Misoperation". Examples given as a "Misoperation" in the spreadsheet included a failed secondary potential breaker (see 1. above - PRC-004-3 greatly expands the equipment utilities must now test on a regular basis). IMPA feels that R1 goes above and beyond a good faith effort to identify a true protection system misoperation. In addition the process of documenting and reporting requirements are onerous and time consuming and could potentially become costly in terms of the dollars required to prove an operation was not a misoperation and in terms of the manpower required to oversee this effort. The BES is a dynamic system that undergoes changes continuously - for a utility to have the ability to foresee all of these real-time changes, anticipate the effect that these changes will have on their protection systems and eliminate all Misoperations is not possible with today's technology.
Response: Thank you for your comment. **The details in the requirements are needed to ensure they are measureable and enforceable. To determine all Misoperations, each Protection System operation must be reviewed with a systematic approach.**		

Organization	Yes or No	Question 2 Comment
Exelon	No	PECO: Similar to what Reliability First Corporation has created; PECO suggests that the five categories of Misoperations should be expanded to provide examples of what would constitute a misoperation vs. a non-misoperation for each of the categories. Exelon Nuclear: SERC Regional Criteria procedure for "Analysis and Reporting of Transmission and Generation Protection System Misoperations," currently includes guidance on misoperation categories and classifications and provides comprehensive examples of misoperation classifications. Such guidance has proved invaluable when determining if an event met the definition for reporting to the Region in accordance with PRC-004. It is strongly suggested that the NERC SDT provide similar guidance to registered entities to ensure timely and consistent reporting. ComEd: A formatting comment; the Requirement number formatting does not align with the questions in the comment form. Assuming question 2 referring to R1 items 1.1 - 1.1.3, question 3 is referring to Requirements R1.2, R1.3 and R1.4. TS&C: The requirement should not be to “have a procedure” The reliability objective should be to record, investigate and if required, develop corrective actions for mis operations. Suggest the Requirement read: R1. The Applicable Entity shall record, investigate and implement corrective action planning for all faults and Misoperations. R1.1 Record all BES faults and Protections System operations. R1.2. Complete an investigation and implement immediate corrective actions within 30 days. R1.3. Report Misoperations each quarter using the reporting template. R1.4. Complete a corrective action plan for each identified Misoperation. Requirements 1.2, 1.3 and 1.4 should be removed and replaced by one requirement. See suggested R1 above. Corrective Action Planning, Performance Improvement, Root Cause Analysis and Investigations are all standard business practices with widely accepted protocols and methodologies. The details concerning the possible outcomes of a CAP should be removed The standard requirements should not try to anticipate the possible outcomes, “cause not identified” and subsequent actions, “interim actions, final actions, timetables etc.” Nor should the standard include a statement requiring an entity to state that there is “no need to develop a CAP” or that “no further investigation is required”.

Response: Thank you for your comments.

PECO: The drafting team revised the definition of Misoperation to include more categories of Misoperations. There are

Organization	Yes or No	Question 2 Comment
examples of each category in the Guidelines and Technical Basis section of the standard. **Exelon Nuclear: The drafting team revised the definition of Misoperation to include more categories of Misoperations. There are examples of each category in the Guidelines and Technical Basis section of the standard.** **ComEd: The original comment form did have errors in reference. The standard has been revised.** **TS&C: The standard has been revised. The requirement to have and implement a procedure has been eliminated.**		
Manitoba Hydro	No	1. R1 should be clarified by changing '… and address all Protection System Misoperations within its system' to '… and address all Protection System Misoperations within its BES'. While the standard only applies to Protection Systems for Facilities that are part of the BES as stated in the Applicability Section, R1.1.1 explicitly states 'BES Faults' and 'BES Protection System operations' making R1 read like it refers to all Protection Misoperations in the Registered Entities' entire system. 2. R1.1.1 and M2 are too prescriptive and should not specify the process that a Registered Entity must follow to determine when a Protection System Misoperation has occurred. 3. R1.1.1 and M2 should only require a process to identify a list of all Protection System Misoperations rather than a list of every single fault and BES protection system operations on the Registered Entity's system.
Response: Thank you for your comments. **1. The application of the standard is by default limited to the Protection System(s) owned by the entity. The text has been revised to refer to the Misoperations of the entity's Protection System(s). The Applicability Section specifically states "Protection Systems for Facilities that are part of the BES".** **2. The details in the requirements are needed to ensure they are measureable and enforceable.** **3. To determine all Misoperations, all Protection System operations must be reviewed with a systematic approach.**		
Tacoma Power	Yes	None
Ameren	No	We assume you mean R1 and R1.1 here. Please 1) review and incorporate the Project 2009-17 interpretations that have been correctly incorporated in PRC-004-1a; the SDT should recognize PRC-004-1a in the Background section to provide correct history and continuity.

Organization	Yes or No	Question 2 Comment
		2) reword R1 to state: "Each … and address its Protection System Misoperations." This removes 'all' because though we strive to find all it is impractical to guarantee all were found. The TO, GO, DP is responsible for the Protection Systems they each own, thus use 'its' and remove 'within its system' for clarity of responsibility. 3) Reword R1.1.1 to replace 'all' with 'its' for the same reasons as 2) above. 4) Reword R1.1.3 to insert 'identified' before Misoperation.
Response: Thank you for your comment. **We recognize there were typographical errors on the comment form.** **1. The mandatory and approved standard PRC-004-2a will be incorporated into this standard and will be recognized in the Background section.** **2. The standard has been revised.** **3. The standard has been revised.** **4. The standard has been revised.**		
Utility Services, Inc.	No	Please refer to our response to Question 1.
Response: Thank you for your comment.		
American Electric Power	No	1. We are confused by the numbering of the requirements in this question versus the numbering within the proposed standard. In addition, rather than developing additional sub-requirements and sub-sub-requirements which make it difficult to track compliance, we suggest discrete requirements which stand on their own. 2. Requirement R1 is not sufficient, because there are additional considerations set forth in the Standard's "Guidelines and Technical Basis section" regarding the identification of Misoperations. Requirement R1 should include a clear reference to the guidelines to lessen the possibility of confusion by an Entity or auditor. 3. 1.1.3 appears redundant with 1.2, as operations must be investigated in order to identify whether or not a misoperation has occurred. In addition, more detail is needed as to the exact intention of the word "address".

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comments. **1. We recognize there were typographical errors on the comment form.** **2. The definition of Misoperation has been modified to be more aligned with the Guidelines and Technical Basis section of the standard. The revised definition is consistent with the NERC System Protection and Control Subcommittee proposed definition of Misoperation.** **3. The standard has been revised; the word "address" has been removed.**		
American Transmission Company, LLC	Yes	
CenterPoint Energy		
BGE	Yes	No comment.
Consumers Energy	No	Suggest removing the term "all" in R1 and R1.1.1 as the Standard should focus only on Misoperations and not evaluation of all operations.
Response: Thank you for your comment. **To determine all Misoperations, each Protection System operation must be reviewed with a systematic approach.**		
ITC	No	1. Within 1.1.1 the wording "and BES Protection System operations" may be interpreted to include all components within a Protection System which could lead to a monumental task and is not necessary if no outage occurred. 2. 1.1.2 should be written to read simpler. Suggested changes: 1.1.1 Document and review all BES Faults or outages caused by BES Protection System operations.1.1.2 Identify and document all Misoperations.
Response: Thank you for your comments. **1. To determine all Misoperations, each Protection System operation must be reviewed with a systematic approach. The revised Requirements deal with Protection System operations and not operation of components.**		

Organization	Yes or No	Question 2 Comment
2. The standard has been revised.		
Wisconsin Electric	Yes	
Duke Energy	No	In the lead-in paragraph for R1, the word "all" should be replaced with "BES" for clarity. NOTE: R1.2, R1.3 and R1.4 are addressed in our response to question #3 below.
Response: Thank you for your comment. **The Applicability Section specifically states "Protection Systems for Facilities that are part of the BES".**		
Constellation Power Generation/Constellation Energy Nuclear Group	No	The documentation requirement under 1.1.1 is too broad and onerous. As an example, some generating units upon shut down may have lockout relays associated with opening the generator breaker. This technically is a protection system operation, but is working as designed. If that same generating unit were to cycle every day, then a report identifying the operation and classifying it as not a misoperation would need to be created every day. Therefore, requiring the documentation of all protection system operations is purely an administrative requirement. The burden of documentation does not encourage reliability and should be carefully considered as part of the standard.
Response: Thank you for your comment. **If the relay is used exclusively for control then it is not considered part of a Protection System. If the reverse power relay doubles for protection and control, review of the relay operation would be necessary when an unexpected operation occurs.**		
Springfield Utility Board		
BC Hydro	Yes	BC Hydro requests clarification for the unintentional protection system operation due to maintenance or testing. Is this unintentional operation considered a misoperation?
Response: Thank you for your comment. **Language has been added to the proposed definition that reads "and is unrelated to on-site maintenance, testing, construction or commissioning activities".**		

3. Requirements R1.2, R1.3, and R1.4 introduce time limits associated with identifying, investigating, and addressing Misoperations. Do you agree with the allotted times? If not, please provide specific reasons why not and alternative recommendations.

Summary Consideration:

Numerous commenters were concerned about the 90-day time limit associated with Requirement 1, Part 1.2 and its expected output; e.g., having completed the investigation including taking necessary outages. The SDT revised the standard by increasing the timelines and clarifying the steps involved to complete the investigation of a Misoperation.

Many commenters were confused about the starting point of the time intervals associated with the Misoperation investigation. The SDT has established the date of the Protection System operation as the reference point.

Other commenters were concerned about compliance with the standard after a natural disaster or significant system event. The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "The Sanction Guidelines of the North American Electric Reliability Corporation, effective January 15, 2008, provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions…"

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	No	(This item actually refers to Parts 1.2, 1.3, and 1.4.) The Part 1.2 time interval of 90 days may not be sufficient, in some cases, to complete investigation due to inability to obtain suitable power system outages where they might be necessary. A T.O. or G.O. should have the authority to determine that a delay in the investigation is less of a power system reliability threat than an inappropriate outage. Although provision for this is made in Part 1.4, the language in Part 1.2 should be changed so as not to prejudge the appropriateness of an owner's actions.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation, which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation, and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either; the Corrective Action Plan when a**		

Organization	Yes or No	Question 3 Comment
cause was determined; or an action plan of additional steps if the investigation failed to determine a cause.		
Public Service Enterprise Group Company	Yes	Requirements R2, R3, and R4 do not exist. If R1-1.2, 1.3, and 1.4 are meant for comment, then the allotted times are agreeable with the following exception. 1. As 1.4 is written it sounds like even after investigating for 90 days and not being able to find a cause for the misoperation, an action plan is needed to continue looking for the cause. The intent of the action plan in 1.4 (as indicated in the second and third full paragraphs on page 15) is not to conclusively determine a cause, but to take actions that may further a future investigation should another misoperation occur. The wording of 1.4 should be revised to reflect the true intent. 2. We suggest changing 90 days in R1.2 to 180 days, and changing 120 days in R1.4 to 210 days (180 +30). In certain cases, root causes may not be able to be fully evaluated in 90 days because lines may need to be removed from service to do so, and clearances may not be granted within the 90-day window. By extending the time frame to 180 days, the time needed for removing lines from service for root cause determination will be sufficient in virtually all cases, thereby eliminating the burden for Corrective Action Plans and the associated requirements of such plans. 3. The first sentence of Section 1.4 should also be changed to read "Within 60 days following June 30 and December 31," and in Attachment 1 the title "Quarterly" should be changed to "Semi-Annual." 4. Other suggestions: Change the second bullet in R1.2 so that it directly refers to R1.4. 5. Also, make R1.2 language "past' tense to be consistent with R1.3 and R1.4.

Response: The SDT thanks you for your comments.

1. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**
2. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent**

Organization	Yes or No	Question 3 Comment
documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. 3. **The drafting team chose to retain Quarterly reporting.** 4. **The SDT revised the standard.** 5. **The SDT revised the standard.**		
Hydro One	No	(Assume this item actually refers to Requirements 1.2, 1.3, and 1.4.) Requirement 1.2 time interval of 90 days will not be sufficient, in some cases, to complete investigation due to inability to obtain suitable power system outages. A T.O. or G.O. should have the authority to determine that a delay in the investigation is less of a power system reliability threat than an inappropriate outage. Although Provision for this is made in Requirement 1.4, the language in 1.2 should be changed so as not to prejudge the appropriateness of an owner's actions.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Tri-State Generation and Transmission Ass'n - System Protection	Yes	The limits for those parts are acceptable (though, as we comment in 4. below, we believe the parts should be individual requirements).
Response: The SDT thanks you for your comment. **The SDT revised the standard.**		

Organization	Yes or No	Question 3 Comment
FirstEnergy	No	1. Various testing or investigating recommendations may require BES equipment be taken out of service to accomplish the appropriate testing and investigation involved with relay Misoperations. This testing may dictate what CAP is appropriate. The time limits stated do not provide any exceptions for equipment which cannot be taken out of service within the time limits identified for operational concerns or when these equipment outages are cancelled by operations based on system integrity concerns. There should be some exceptions for these instances.R1.2 prescribes 90 days to investigate the misoperation. 2. Compliance section 1.4 prescribes 60 days following the end of each calendar quarter to provide periodic data submittal. This timing will create a situation where the last month of the reporting time period will not yet be due for completion of the original investigation. We suggest the compliance section 1.4 agree with the 90 day investigation period so that all original investigations are completed at the time of the data submittal.
Response: The SDT thanks you for your comments. 1. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.** 2. **The drafting team retained the current time frames for reporting.**		
Pepco Holdings Inc Affiliates	No	**1.** The 90 day window to conduct an investigation and identify the cause of a protective system misoperation is not practical in many situations and unreasonable. Outage windows for transmission facilities are highly dependent on weather and system loading conditions and as such are usually relegated to only a relatively few months during the Spring and Fall. Also, during these mild weather / low load times any outage request submitted to investigate a protective system misoperation is competing with numerous other construction related outage requests being evaluated by the Transmission Operator for TPL infrastructure upgrades in addition to other

Organization	Yes or No	Question 3 Comment
		facility maintenance outages. The Transmission Operator typically requires a minimum 30 day lead time for scheduling outages on BES facilities. Granting of these outages is the sole responsibility of the Transmission Operator, not the Transmission Owner. Canceling of the outage by the Transmission Operator may require the Transmission Owner to go through the 30 day re-submittal process. Denial of an outage request by the Transmission Operator could delay the misoperation investigation and force the Transmission Owner to be in non-compliance. An emergency outage could be declared to enable a misoperation investigation to take place, but depending on loading and system conditions, the facility forced outage could result in an increased reliability risk to the system, and/or the need to run expensive off cost generation. Declaration of an emergency outage should rarely be used, only for those instances of very high risk.In summary, it is not practical in many situations or reasonable to expect the Transmission Owner to be responsible to investigate the cause of a misoperation within 90 days when they have no control over the outage scheduling and approval process. As such, both the 90 and 120 day time frames should be removed entirely from the standard (i.e., structure the requirements similar to existing PRC-004-1 & PRC-004-2). Alternatively, but not recommended, would be to develop time frames only for those activities over which the Transmission Owner has full control. This second approach would of course require an extensive rewrite of Requirements R1.2, R1.3 and R1.4 and would in the end contribute little to improving the timeliness of investigations, since the majority of the time consumed in the investigation process is waiting for outages to be granted. For example, a requirement could be established that "within 45 days of the date of each identified misoperation launch an investigation into the cause and submit an outage request for any facility outages as necessary for diagnostic testing." These tasks are within the Transmission Owners control. However, completion of the investigation cannot be bounded since the outage process is indeterminate and out of the control of the Transmission Owner. **2.** Similarly, since the development of the corrective action plan is dependent on completing the investigation (which is outage dependent), development of the CAP cannot be bounded either. Because of this it is recommended that all time frames be removed.
Response: The SDT thanks you for your comment.		

Organization	Yes or No	Question 3 Comment
1. The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. The standard allows for extended investigation periods in Requirement R4. **2. The CAP is developed after the investigation is completed and the cause determined.**		
Southern Company Generation	No	There are no requirements R2, R3, and R4 in the 09 Jun 2011 Draft #1 posted in the "Standards Under Development" NERC web site. Responding to these actions as written in R1.2, R1,3, and R1.4 of the draft standard, we believe that specifying so many deadlines for individual tasks will make the identification, investigation, analysis process too cumbersome. The periodic reporting requirements to the regional entity requires continuing attention to these tasks and is sufficient to ensure their completion.
Response: The SDT thanks you for your comment. **The SDT revised the standard. Timelines are included in the standard to ensure entities have clearly identifiable targets in investigating and correcting a Misoperation. The SDT believes the timelines in the requirements enhance reliability and are measureable and enforceable. Periodic reporting requirements to the Regional Entities cannot sufficiently achieve the reliability objectives of the Standard.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	We don't agree with placing a timeframe on the investigation of a misoperation. There is an inconsistency with section 1.2 of the application guidelines and section 1.2 of R1. One states that its 90 days from the identification of the misoperation and the other states from the date that the misoperation occurred. If it's the case that the 90 days start from the occurrence of the misoperation we are concerned that putting a timeframe on the analysis would cause detriment analysis especially during system wide event I.E hurricane. Could cause hundreds of operations and would need a longer analysis timeframe for these. Could add a process by which the entity could file for extension

Organization	Yes or No	Question 3 Comment
		during these extraordinary circumstances. Was the intent for the timeframes to start after the misoperation was identified or was the intent to start the clock after the operation occurs? In the question it should have read R1.2, 1.3, 1.4 rather than R2, R3, R4.
Response: The SDT thanks you for your comment. **The SDT revised the standard based on your comment. The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "The Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions."**		
MRO's NERC Standards Review Forum	No	We agree with the time tables/time lines if a bullet is added to allow the Regional Entity to grant the registered entity an extension beyond the 90 days within R1.2 and beyond the 120 days within R1.3 and R1.4.
Response: The SDT thanks you for your comment. **The SDT revised the standard and believes the new timeframes in the standard are sufficient.**		
Electric Market Policy	No	Question states R2, R3, and R4. Assume the question is referring to (R1.2), (R1.3), and (R1.4)? 1. (R1.3) and (R1.4) does not give appropriate time to gather data, run studies and perform field investigations for complex events where a Misoperation can occur. Recommend changing the 120 day requirement to 180 days. 2. Remove Box with "Rationale for R1". It is not needed in the standard. 3. In (R1.2), (R1.3), (R1.4) and (R1.5) the requirement wording starts with "A requirement...", recommend removing "A requirement that" in each section. Suggest wording change as follows: R1.2 The responsible entity shall within 90 calendar days of each identified Misoperation, investigate each Misoperation to determine its cause and do one of the following: R1.3 The responsible entity shall within 180 calendar days of each Misoperation for which the cause was identified develop one of the following:R1.4 The responsible entity shall within 180 calendar days of each Misoperation for which the cause was not identified develop one of the following:

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comments. **1. The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.** **2. The Rationale boxes are part of the new Results Based Standard Template. As noted in the "Definition of Terms Used in the Standard", once PRC-004-3 has received ballot approval, the Rationale boxes will be moved to the Application Guidelines Section of the standard.** **3. The standard has been revised.**		
Pacific Northwest Small Public Power Utility Comment Group	No	While we realize many entities may want or need the structure presented, we can see situations where the cause would be immediately evident and can and should be rectified at the time of the initial site visit. The problem and corrective action would then be documented afterward. While the second bullet of 1.3 suggests this might be allowed, it is not explicitly so stated. In the name of reliability, shortcuts such as this should be explicitly allowed in order to avoid repeated identical Misoperations caused mainly by the standard process itself.
Response: The SDT thanks you for your comment. **In your example, if the corrective action is immediately completed then a CAP would be documented and the completion date indicated.**		
LG&E and KU Energy	No	We assume the SDT is referring to R1.2, R1.3, and R1.4 as there are no other requirements shown as R2, R3, and R4. Therefore, we have the following comment on R1.3:On Requirement R1.3, could the SDT clarify a little bit better that only a timetable and plans are needed to be completed within the 120 days, and not that the entire correction be completed within 120 days. Currently, R1.3 could be interpreted either way. Therefore, so that an auditor would not interpret it that the corrective action plan needs to be completed within 120 days, this needs to be clarified. Because GO's oftentimes have to wait to complete a corrective action plan until the next outage on a

Organization	Yes or No	Question 3 Comment
		unit, which would probably be greater than 120 days.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. New Requirement R3 does not indicate the CAP must be completed, only developed. New Requirement R4 requires completion of a CAP according to the work timetable. The entity has the ability to establish and revise the timeline for completion of its CAP or action plan.**		
APM Members		
PPL Generation	No	1. Requirement 1.2 states, "A requirement that the Registered Entity shall, within 90 calendar days of each identified Misoperation, investigate the Misoperation to determine its cause(s)." This should be clarified to be "within 90 calendar days of identifying a Misoperation." 2. Requirement 1.3 indicates within 120 days, the Registered Entity shall develop a CAP that includes "Final corrective or mitigating actions to reduce potential impacts to BES reliability." This should be clarified to be "Final corrective or mitigating actions the Registered Entities plans to complete that reduce potential impacts to BES reliability." It should be clear that not all "Final corrective or mitigating actions" need to be complete by the 120-day timeframe. Also, as suggested above, the language "within 120 calendar days" should be clarified to be "within 120 calendar days of identifying a Misoperation."
Response: The SDT thanks you for your comments. 1. **The SDT revised the standard for clarity.** 2. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection**		

Organization	Yes or No	Question 3 Comment
System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. New Requirement R2 does not indicate the CAP must be completed, only developed. New Requirement R4 requires completion of a CAP according to the work timetable. The entity has the ability to establish and revise the timeline for completion of its CAP or action plan.		
Florida Municipal Power Agency	No	see comments to Question 1
Response: The SDT thanks you for your comment. **See our response to your comment in Question 10.**		
Bonneville Power Administration	Yes	BPA believes the allotted time seems adequate.
Response: The SDT thanks you for your comment.		
Western Area Power Administration	Yes	
Westar Energy	No	1. Requirements R1.2, R1.3, and R1.4 introduce time limits. The requirements need additional clarification on the timeframes. Are the timeframes from when the operation occurs or from when the operation is determined to be a Misoperation? 2. Exemptions to the established timeframes should be available in cases of large scale events. 3. R1.2 - remove the requirement to document causes that were ruled out, overly burdensome and unnecessary. 4. R1.3 - Remove the reference or specifically define what constitutes a declaration. 5. R1.4 - remove or refine, overly burdensome and unnecessary. 6. R1.5 - remove, vague and unnecessary.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comments. 1. **The SDT revised the standard for clarity.** 2. **The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "The Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions."** 3. **The SDT revised the standard.** 4. **A declaration in regards to the requirements of this standard is a statement explaining why you did not need a CAP or why no further actions will be taken. The SDT is not specifying the format of a declaration.** 5. **The SDT revised the standard. Timelines are included in the standard to ensure entities have clearly identifiable targets in investigating and correcting a Misoperation. The SDT believes the timelines in the requirements enhance reliability and are measureable and enforceable.** 6. **The SDT revised the standard, but disagrees with your comment. Completion of the CAP or action plan is necessary to correct the causes of Misoperations.**		
Georgia Transmission Corporation	Yes	Agreed in principle, however the question should be R1.2, R1.3 and R1.4. Not R2, R3, R4.
Response: The SDT thanks you for your comment. **We recognize there were typographical errors on the comment form.**		
PacifiCorp	Yes	
NextEra Energy, Inc.	Yes	(Refers to Requirements R1.2, R1.3 & R1.4)
Response: The SDT thanks you for your comment. **We recognize there were typographical errors on the comment form.**		
Southern Company	No	The 90 day and 120 day periods are acceptable; however, the start of the 90 day and 120 day periods requires clarification that time is measured from the "date of occurrence of

Organization	Yes or No	Question 3 Comment
		each identified Misoperation."
Response: The SDT thanks you for your comment. **The SDT revised the standard for clarity.**		
Flathead Electric Cooperative, Inc.	Yes	
Green Country Energy	Yes	Just a comment for possible exceptions. When gathering data from manufacturers the 90day time frame can be aggressive. e.g. (GE) some language added to allow for information gathering time outside of the entities control would be helpful.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Hydro-Quebec TransEnergie	Yes	
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration believes that 90 days is generally enough to assess a Misoperation - or to have evaluated and documented multiple possible causes if the source of the Misoperation cannot be determined. The 120 day corrective action plan time frame is acceptable to us as well.
Response: The SDT thanks you for your comment.		
Oncor Electric Delivery	Yes	
Private Citizen	No	See my comments on Question 9.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comment. **See our answer to your comments in Question 9.**		
Consolidated Edison Co. of NY, Inc.	No	(Assume this item actually refers to Requirements 1.2, 1.3, and 1.4.) Requirement 1.2 time interval of 90 days will not be sufficient, in some cases, to complete investigation due to inability to obtain suitable power system outages. A T.O. or G.O. should have the authority to determine that a delay in the investigation is less of a power system reliability threat than an inappropriate outage. Although Provision for this is made in Requirement 1.4, the language in 1.2 should be changed so as not to prejudge the appropriateness of an owner's actions.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Orange and Rockland Utilities, Inc.	Yes	By selecting "Yes", we assume "R2, R3, and R4" mentioned here are actually "R1.2, R1.3, and R1.4" due to there are no R2, R3, and R4 in this new version (3).
Response: The SDT thanks you for your comment. **We recognize there were typographical errors on the comment form.**		
PSE	Yes	
TransAlta	No	There are no requirements R2, R3 and R4 on PRC-004-3
Response: The SDT thanks you for your comment. **We recognize there were typographical errors on the comment form.**		

Organization	Yes or No	Question 3 Comment
Entergy Services	No	For Misoperation corrective action plans which could require out of budget cycle funding, significant project coordination with other groups or entities, and/or require major outage considerations, 120 calendar days is too aggressive to meet a corrective action plan development requirement which includes "final corrective or mitigating actions.....". We suggest the timing for R1.3 and R1.4 be 120 days following the completion of R1.2. Therefore, we suggest the wording for R1.3 and R1.4 be revised to:1.3 A requirement that for all Misoperations for which the cause(s) was (were) identified, the Registered Entity shall, within 120 calendar days following the completion of the investigation in R1.2, develop one of the following: 1.4 A requirement that for all Misoperations for which the cause(s) was (were) not identified, the Registered Entity shall, within 120 calendar days following the completion of the investigation in R1.2, develop one of the following:
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
GenOn Energy	No	The intent is understood: to promote timely investigations and responses. However, the allotted times assumes that scheduling outages for investigation, testing, or maintenance are easy to obtain in every instance. 90 days is insufficient time for seasonal periods lasting five or six months or more.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		

Organization	Yes or No	Question 3 Comment
Indiana Municipal Power Agency	No	The times as listed are aggressive, especially for smaller utilities that have facilities whose loss would have minimal impact on the BES. It may be more appropriate to break the time limits into different categories, such as operations (and Misoperations) that impact critical facilities versus those operations that impact facilities that are not critical to the BES. For instance the time limits listed should apply only to critical facilities. For non-critical facilities the times should be extended to 180 days from the date of a Misoperation to complete the investigation and 240 days to develop a plan or otherwise address the Misoperation.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. The SDT believes the time interval is sufficient to establish a suspected cause, or plan further steps for the investigation. This standard is applicable to BES facilities as listed in the Applicability section.**		
Exelon	Yes	PECO: **1.** Time limits are reasonable; however, the drafting team should consider requests for extensions based on extenuating circumstances, i.e. emergent work/storm related issues, etc., related to R1.2, R1.3, and R1.4. **2.** It is not clear what the deferral reference on page 15 of 16 of the Application Guidelines refers to. It appears to allude to a deferral process for CAPs but this is not specifically identified in R1.5 of the standard. ComEd: For R1.3, is there an intended limit on the work time table? Coordinating mitigating actions between customer premises or other entities can extend corrective plans significantly. Exelon Nuclear: Time limits are reasonable; however, the SDT should strongly consider a provision for those events where the root cause of a Misoperation may be dependent on an external investigation (e.g., a relay may have to be examined by the manufacturer in an attempt to determine a defect). The timeline associated with forensics performed by

Organization	Yes or No	Question 3 Comment
		an external company are outside the control of the registered entity.

Response: The SDT thanks you for your comments.

PECO

1. **The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "The Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions."**
2. **The standard has been revised. New Requirement R4, Part 4.2: "Maintain detailed implementation records of each CAP or action plan including dated information surrounding any revision(s) and completion".**

ComEd

The work timetable needs to reflect mitigating measures as a result of the Misoperation; depending on the scope of the corrective action it is impossible to generally impose such time limits on the work plan.

Exelon Nuclear

The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.

Manitoba Hydro	Yes	
Tacoma Power	No	The Guidelines and Technical Basis section asserts that the 90 and 120 day timeframes "provide sufficient time for the responsible entity to get through a seasonal period that can restrict the ability to take the outages necessary to effectively identify the Misoperation root cause(s) or document the investigation for unsolved root causes." For some responsible entities, this period arguably could approach 6 months (180 days). Exacerbating this issue is the fact that the VSL increases rapidly after the 90 and 120 day timeframes are exceeded. While identification, analysis, and correction of protection system mis-operations is important to reliability of the BES, the responsible entity should be granted greater latitude to triage investigations based upon the perceived severity of

Organization	Yes or No	Question 3 Comment
		the nature of the mis-operation with respect to other operational constraints. Not all mis-operations are equal in potential impact. Investigating a mis-operation should not degrade system reliability in the name of compliance, and the 90 and 120 day timeframes may result in undue hurried response for some, less critical mis-operations.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause. The SDT believes the timelines provide sufficient latitude for the entity to prioritize Misoperation response.**		
Ameren	No	**1.** We don't see R2, R3, and R4 in the posted document; We assume the SDT mean R1.2, 1.3 and 1.4. **2.** From our perspective, the SDT rationale for R1 is flawed. Using the posted TADS 2008 and 2009 reports, Failed Protection System Equipment is only responsible for 1.1% of the hours of AC Circuit Sustained Outages and ranks as the 9th Cause Code. Considering the large number of sustained outages, even larger number of momentary outages, and huge number of non-outage hours in which the Protection System correctly restrained, the Protection System is extremely reliable across a wide range of conditions and numerous challenges. We agree that Misoperations should be investigated and corrective actions taken if a reasonable cause is found, but the importance of this issue is being overstated. **3.** In R1.2, please replace '90 calendar days' with 'six calendar months' to allow sufficient investigation time in non-peaking periods because BES equipment outages are needed for a fair number of investigations. **4.** In R1., please restate as " A requirement that for each Misoperation for which the cause(s) was (were) identified, the Registered Entity shall, within 120 calendar days of the cause being identified per R1.2, develop one of the following ..." because the Corrective Action Plan cannot be developed until after the cause is identified. **5.** R1.4 also needs to be 120 days subsequent to initial field investigation of R1.2, similar

Organization	Yes or No	Question 3 Comment
		to R1.3, and replace 'all' with 'each'.
Response: The SDT thanks you for your comments. 1. **We recognize there were typographical errors on the comment form.** 2. **The majority of Protection System operations are correct. However PRC-004-3 is intended to address Protection System Misoperations on the BES. The SDT believes the timelines in the requirements enhance reliability and are measureable and enforceable. The activity of identifying and mitigating these Misoperations is essential to maintaining reliability of the BES.** 3. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.** 4. **The SDT revised the standard.** 5. **The SDT revised the standard.**		
Utility Services, Inc.		
American Electric Power	No	**1.** There is no R2, R3, and R4 in the current draft of the standard. **2.** Also, the process needs to accommodate for the later identification of a misoperation after new information is obtained. Some investigations might take a month after an event occurs before that event could or would be declared a misoperation.
Response: The SDT thanks you for your comments. 1. **We recognize there were typographical errors on the comment form.** 2. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause**		

Organization	Yes or No	Question 3 Comment
is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.		
American Transmission Company, LLC	No	What about wide scale events such as the 2003 blackout? There does not appear to be an exception. ATC suggests that a provision be made to allow for declaration of an extension of the timelines identified in requirements R1.2, R1.3 and R1.4 in the case of a wide scale system event (NERC event categories 4 or 5).
Response: The SDT thanks you for your comment. **The SDT revised the Guidelines and Technical Basis section of the standard to include the following statement regarding extenuating circumstances: "The Sanction Guidelines of the North American Electric Reliability Corporation effective January 15, 2008 provides that the Compliance Monitor will consider extenuating circumstances when considering any sanctions."**		
CenterPoint Energy		
BGE	No	R1.2 through R1.4 require the registered entity to complete various phases of a misoperation investigation by specific times. In general the times are generous enough to comply with, but the fact is many investigations require transmission facility outages that must be approved by the Transmission Operator, and these may not be granted. To meet the timeline set forth in the Requirements the Registered Entity may have to declare an emergency outage and accrue the expense of running off cost generation. While this requirement is seemingly reasonable, it unreasonably holds compliance by the Registered Entity hostage to the entities who have no "skin in the game".
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		

Organization	Yes or No	Question 3 Comment
Consumers Energy	No	The time limits should be from the date of identification of a Misoperation and not the date of the Misoperation. This will allow for the time required to gather information from the field to determine if a Misoperation has actually occurred.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
ITC	No	Because of coordination to shutdown the associated equipment, the time to investigate may exceed the time limit of 90 calendar days following the misoperation.
Response: The SDT thanks you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Wisconsin Electric	Yes	1. The second bullet under R1.2 is unnecessary given R1.4. 2. Also, replace “timetable” with “schedule” in 1.3, 1.4, and 1.5. 3. The “...was (were) ...” references in R1.3 and R1.4 should be replaced with the plural case alone for clarity. E.g, “...for all Misoperations for which the causes were identified.”
Response: The SDT thanks you for your comments. **1. The SDT revised the standard.** **2. The use of the word “timetable” is consistent with the NERC Glossary definition of a Corrective Action Plan (CAP).**		

Organization	Yes or No	Question 3 Comment
3. The SDT revised the standard.		
Duke Energy	No	1. R1.2 - replace the phrase "identified Misoperation" with the phrase "Protection System Operation" to clarify that the clock starts with the Protection System Operation, not when you identify a Misoperation. 2. Also replace the phrase "investigate the Misoperation" with the phrase "analyze any Misoperation". 3. R1.2 first bullet - Reword as follows: "For each Misoperation where the cause(s) are identified, document the analysis and the cause(s) determined." 4. R1.2 - Increase the time to 120 calendar days and note under the second bullet that where a transmission or generation outage is required to complete an analysis (i.e. nuclear switchyard), it's permissible to document that as additional steps planned to identify the cause(s). 5. R1.2 second bullet - Change the word "investigation" to "analysis". 6. R1.3 - Change 120 to 60 calendar days, and replace the phrase "of the Misoperation' with the phrase "of completing the analysis in R1.2". 7. R1.4 - Delete R1.4 because it is redundant to parts of R1.2 and R1.3 8. R1.5 - Modify R1.5 so that a Registered Entity can revise its CAP or action plan as outlined in its timetable, in order to deal with changes in outage schedules, etc.
Response: The SDT thanks you for your comments. 1. **The SDT revised the standard.** 2. **The SDT revised the standard.** 3. **The SDT revised the standard.** 4. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine**		

Organization	Yes or No	Question 3 Comment
a cause. 5. The SDT revised the standard. The SDT believes the word "investigate" is a more comprehensive term that includes "analysis", and we believe is a more appropriate word for the requirement. 6. The SDT revised the standard. 7. The SDT revised the standard. 8. The SDT revised the standard.		
Constellation Power Generation/Constellation Energy Nuclear Group	No	The "no" response is due to confusion in the question. We suspect that the requirements intended for reference were R1.2, R1.3 and R1.4. The time allotments seem reasonable.
Response: The SDT thanks you for your comment. We recognize there were typographical errors on the comment form.		
Springfield Utility Board		
BC Hydro	Yes	

4. The team has included VRFs, VSLs, and Time Horizons with this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for change.

Summary Consideration:

1. Many commenters suggested dividing Requirement R1 into several requirements so that the VRFs could be set at different levels, rather than 'High' for all of the Parts of the old Requirement R1. The drafting team agreed and separated Requirement R1 into four requirements with appropriate VRFs and VSLs.
2. Many commenters believed the VSL matrix was too complex. Separating the single requirement into four requirements resolved this issue.
3. Many commenters questioned the VSL assignments. The drafting team included new VSLs to reflect the new requirements.
4. The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".
5. One commenter wanted the "Operations Planning" Time Horizon removed but the SDT believes the Time Horizons are appropriate for each of the new requirements.

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council	No	As noted in the comment above, a T.O. or G.O. may be held to be inappropriately non-Compliant due to delaying an investigation until a safer outage window may be available. Many factors affect power system reliability, and an entity should have leeway to determine which is most important.
Response: Thank you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation,**		

Organization	Yes or No	Question 4 Comment
investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.		
Public Service Enterprise Group Company	No	Setting the VRF as HIGH seems to indicate there is no time to waste in finding and correcting the cause of the misoperation, yet 90 days are allowed currently to investigate, and another 30 days are allowed to develop a Corrective Action Plan, for which there is no timeframe given for completing other than to document a timeframe and abide by it. Because of this long timeframe in the standard as currently drafted, a VRF of MEDIUM is appropriate.
Response: Thank you for your comment. **The drafting team agrees with your comment in principle and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
Hydro One	No	As noted in the comment above, a T.O. or G.O. may be held to be inappropriately non-Compliant due to delaying an investigation until a safer outage window may be available. Several factors affect power system reliability and an entity should have leeway to determine which is most important.
Response: Thank you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Tri-State Generation and Transmission Ass'n - System Protection	No	The Requirement R1 should be split into several requirements with individual VRFs and VSLs. For example, the Measure associated with Requirement R1, Part 1.1 is primarily administrative in nature and should not have a “High” VRF.
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.		
FirstEnergy	No	We do not agree with a HIGH VRF for the sole requirement in the proposed standard. We believe that not having a procedure for handling Misoperations is much less of a risk to reliability than the actual reporting of the Misoperations. We suggest that having a procedure requirement be assigned a LOW VRF, and the requirement to implement be assigned a "MEDIUM" VRF. Since this standard pertains to after-the-fact reporting, there is no immediate risk to the BES and none of the requirements therefore warrant a HIGH VRF.
Response: Thank you for your comment. **The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
Pepco Holdings Inc Affiliates	No	Most of the VSL's are related to the time frames with which the misoperation investigation is completed, or the corrective action plan developed. Both of these are completely dependent on the availability of outages to perform diagnostic testing to determine the cause of the misoperation. As described extensively in Question #3 the Transmission Owner cannot be held responsible to complete these tasks within a specified time frame when they have no control over the outage scheduling and approval process. 1. Compliance should be judged on whether all BES events were reviewed, an investigation conducted and a corrective action plan developed and implemented. Not whether these activities were completed within some arbitrarily chosen time frame. 2. Compliance could also be judged on the timeliness and completeness of the quarterly data submittal mentioned in section C1.4 of the standard.
Response: Thank you for your comments. **1. The drafting team has assigned VSLs in accordance with FERCs June 19, 2008 Order on Violation Severity Levels, as well as NERCs VSL guidelines. The drafting team extended the timeframes in the standard based on industry comments. The drafting team believes it is important to meet the established timeframes and has set the VSLs appropriately.** **2. The SDT agrees with your comment.**		

Organization	Yes or No	Question 4 Comment
Southern Company Generation	Yes	The VRF needs to be high as is specified in the draft. The magnitude of the components that make up the VSL matrix in the proposed draft #1 is indicative of the excessively prescriptive composition. The requirements, measures, and violation severity levels need to be simplified as described in the comment to question 2 above.
Response: Thank you for your comments. **The drafting team has assigned VSLs in accordance with FERCs June 19, 2008 Order on Violation Severity Levels, as well as NERCs VSL guidelines.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	See comment in question two.
Response: Thank you for your comment. **See our response in Question 2.**		
MRO's NERC Standards Review Forum	No	The VSLs are incorrect. 1. All documentation time frame references should be deleted. 2. If they are retained the VRF for R1 should be dropped to lower as the requirement is now administrative documentation. Documentation does not affect the electrical state or capability of the bulk electric system. The non documentation items under the severe VSLs can be modified to fit the moderate, high, and severe categories as follows: Moderate: The responsible entity did not identify all protection system Misoperations High: The responsible entity did not investigate all identified protection system Misoperations Severe: The responsible entity did not have a procedure to address protection system Misoperations OR the responsible entity did not implement a plan to correct any Misoperations.
Response: Thank you for your comments. **1. The drafting team has retained the timeframe references because they are used to ensure that all operations are**		

Organization	Yes or No	Question 4 Comment
examined and that all Misoperations are discovered and action plans are developed in a timely manner. 2. The drafting team agrees in principle and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.		
Electric Market Policy	No	Adjust the VSL time horizons and Application Guidelines to reflect a change in (R1.3) and (R1.4) from 120 days to 180 days.
Response: Thank you for your comment. The VSLs and time horizons are based on the new requirements.		
Pacific Northwest Small Public Power Utility Comment Group		
LG&E and KU Energy		
APM Members	No	1. We disagree that the VRF is consistent with other Reliability Standards. The SDT cites the need to deviate from the Medium VRF assigned to the similar requirement of EOP-004-1 R2 because it does not include implementation of corrective actions after the analysis. We disagree with this assessment as there is an implied obligation to implement any recommendations from analysis done to comply with EOP-004-1 R2. NERC investigative and enforcement personnel have routinely expected implementation of corrective actions from investigations. Thus, for consistency (as required by FERC Guideline 3), the VRF for PRC-004-3 R1 should be Medium. 2. We disagree with inclusion of Operations Planning in the Time Horizon. This is a backwards looking analysis. While it does correct for forward looking operations, it is not intended for planning but to simply correct an operational issue. Otherwise, Operations Assessment should be eliminated as a category as the purpose of looking backwards is to correct operations going forward and another category would always be selected along with Operations Assessment. 3. Any late completion of the CAP results in a High VSL. The drafting team should consider graduated steps based on the lateness of completion. Missing the CAP completion work timetable by a few days is not nearly as big a violation as missing the CAP work timetable by

Organization	Yes or No	Question 4 Comment
		months. 4. The second to last High VSL expands upon the requirement by mentioning delivery dates which would violate FERC Guideline 3 for VSLs. The requirements establish that a work timetable must be established. A timetable could be based on quarters rather than specific dates. If specific dates are desired, the requirement should be fine tuned to make this clear. 5. Several of the VSLs mention a "declaration". These VSLs should be expanded to match the language of the requirement more closely for clarity.
Response: Thank you for your comments. **1. The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.** **2. The standard has been revised and the Time Horizons have been established for the new individual requirements. Time Horizons correspond to the period of time it could take to mitigate a violation of the requirement.** **3. The drafting team modified the VSLs.** **4. The drafting team modified the VSLs.** **5. The separation of the requirements and the new VSLs clarify the usage of the term "declaration," which is used in the requirements.**		
PPL Generation		
Florida Municipal Power Agency	No	See comments to Question 1.
Response: Thank you for your comment. **See our response to your comment in Question 1.**		
Bonneville Power Administration		
Western Area Power		

Organization	Yes or No	Question 4 Comment
Administration		
Westar Energy	No	
Georgia Transmission Corporation	Yes	
PacifiCorp		No comments.
NextEra Energy, Inc.	No	NextEra Energy thinks there should be flexibility with Corrective Action Plans (CAPs) and action plans. CAPs and action plans will involve steps that are prepared at a time when all relevant information is not available. As such, there may be a need to modify the CAPs and action plans as additional information becomes available. (See proposed text for Requirement R1.3 and R1.4 in the response for question 9 below.)
Response: Thank you for your comments. **The drafting team made modifications in the new Requirement R4 to add the flexibility to update a CAP.**		
Southern Company		Not Applicable
Flathead Electric Cooperative, Inc.	No	
Green Country Energy		
Hydro-Quebec TransÃ ‰ nergie	Yes	
Ingleside Cogeneration LP	No	Ingleside Cogeneration LP does not believe that a Severe VSL is appropriate if a Protection System operation with an obvious cause is not captured in a summary listing (R1.1 and M2). We understand the need for a rigorous review process, but in many cases, a thorough evaluation is just not needed.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **The drafting team has revised the requirements but retained the requirement to review all operations in order to discover all Misoperations. New VRFs and VSLs have been assigned.**		
Oncor Electric Delivery	Yes	
Private Citizen		
Consolidated Edison Co. of NY, Inc.	No	As noted in the comment above, a T.O. or G.O. may be held to be inappropriately non-Compliant due to delaying an investigation until a safer outage window may be available. Several factors affect power system reliability and an entity should have leeway to determine which is most important.
Response: Thank you for your comment. **The SDT revised the standard. The time interval establishes a timeline for the investigation and subsequent documentation of the Misoperation which would include analyses of relay targets and Disturbance Monitoring Equipment records. The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the findings whether or not a cause is identified. The standard was further modified to allow a time period of 60 days to develop either the Corrective Action Plan when a cause was determined or an action plan of additional steps if the investigation failed to determine a cause.**		
Orange and Rockland Utilities, Inc.	Yes	
PSE	Yes	
TransAlta	Yes	
Entergy Services	No	A single high VRF is too broad to be applied for all elements and geographical areas of the electrical system. Also, lower and moderate VSL assignments should be included for the corrective action plan completion timeline requirements.
Response: Thank you for your comment.		

Organization	Yes or No	Question 4 Comment
The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.		
GenOn Energy	No	1. VRFs are worst-case one-size fits all. The risk applied to a 500kV transmission line is the same applied to a radial connected 75 MW generating unit on a 138kV system. 2. The risk applied to the implementation of a corrective action plan is the same applied to post correction record keeping.
Response: Thank you for your comments. **1. The drafting team is following all the guidelines for assigning VRFs. Risk applied to the criticality of individual Facilities is not a part of the VRF assignment.** **2. The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
Indiana Municipal Power Agency	No	1. IMPA believes that all the sub-requirements should have their own individual VSL and VRF (similar to BAL-006-2). 2. When assigning VRFs and VSLs to the requirement and sub-requirements, the SDT needs to keep in mind the name of the standard is Analysis and Mitigation of Transmission and Generation Protection System Misoperations. The title is NOT Analysis and Mitigation of Transmission and Generation Protection System Operations. The way the draft is currently written if one operation is missed and it is not documented and reviewed then an entity has violated a requirement with a high Violation Risk Factor and a severe Violation Severity Limit even if no misoperation has occurred.
Response: Thank you for your comment. **1. The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.** **2. The drafting team has retained the requirement to document and review all operations in order to discover all Misoperations. The VRFs and VSLs have been modified.**		
Exelon	No	1. ComEd: For R1 VSL, not all potential actions can be identified based on ability to obtain outages associated with an investigation and many times an investigation start leads to

Organization	Yes or No	Question 4 Comment
		other paths. If an entity then creates generic all encompassing check list to meet the intent of R1, would they be held accountable to complete all the items listed when the cause was found at step 3 of 50 as an example. 2. Exelon Nuclear: Suggest rewording the VSL to state that "... either identified the cause or listed the preliminary actions planned to identify the cause ..." to address the concern that not all potential actions may be able to be identified within the required timeline.
Response: Thank you for your comments. **1. The requirement has been revised to identify and review all Protection System operations and designate each Protection System Misoperation. Once the cause of the Misoperation is identified, the entity should proceed to the development of the CAP. The VSLs are based on the new requirement.** **2. The drafting team has adjusted the VSLs to reflect the new requirement.**		
Manitoba Hydro	No	Manitoba Hydro suggests that the sub-requirements of R1 are split into separate requirements (e.g. R1, R2, R3, etc.) or each of the sub-requirements are assigned a separate VSL. The current VSL matrix is unclear.
Response: Thank you for your comment. **The drafting team agrees in principle and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
Tacoma Power	No	An automatic VSL of severe should not be assigned by failure to review one event. A VSL structure similar to draft 4 of PRC-005-2 is more reasonable. It seems reasonable that an entity should be penalized less severely if a lower percentage (1) of BES faults and BES Protection System operations have been documented and reviewed, (2) of Misoperations have been identified and documented, or (3) of Misoperations have been investigated and addressed. Part of the concern is that an entity may be heavily penalized for failing to identify a misoperation, based upon a later finding or a technicality, even if the entity has performed due diligence. Such a later finding may place an entity in a Severe VSL category, and a fear of such a scenario may cause an entity to devote an unreasonable amount of resources to develop or implement its procedure per this draft standard, particularly for arguably less severe Misoperations.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **The drafting team has retained the requirement to document and review all operations in order to discover all Misoperations. The VRFs and VSLs have been modified.**		
Ameren	No	1) R1 VRF should be Low because the risk to BES reliability from one BES Fault or one BES Protection System operation not being documented and reviewed this very minute. The SDT itself alleges that up until now there are not even required Regional Entity procedures to support PRC-004-2, which would lead to numerous omissions in such regions. Operating as such under the proposed PRC-004-3 would lead to numerous High VRF and Severe VSL violations. One would expect a very unreliable BES over the past 4 years; however, the BES has been extremely reliable in this time frame. 2) The VSL need to be completely restated to recognize that a higher volume and BES voltage level >200kV Misoperations deserve a higher severity level, but fixing the number of days an entity is late at 90 days. For example, if an entity is unaware of one Misoperation on the <200kV, they'll end up missing all the deadlines; this belongs in the Lower VSL category. But one omitted Misoperation on the >200kV belongs in Moderate VSL. We propose <200kV omission quantities of 1, 2 to 4, 5 to 10, and >10 Misoperations in the Low, Moderate, High, and Severe VSL respectively. We propose >200kV omission quantities of 1, 2 to 4, and >4 Misoperations in the Moderate, High, and Severe VSL respectively. Similarly missing R1 deadlines by >90 days for identified Misoperations of the same number (1, 2 to 4, etc.) and voltage level would fall into our proposed VSL categories.
Response: Thank you for your comments. **1. The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.** **2. The drafting team is following the guidelines for assigning VRFs. Risk applied to the criticality of individual Facilities is not a part of the VRF assignment. The VSLs are categorized based on the extent of non-compliance to a requirement.**		
Utility Services, Inc.		
American Electric Power	Yes	Though we agree overall with the VRFs, VSLs, and Time Horizons specified, the table seems more complex than necessary due to the number of "or" clauses involved. Should the sub-

Organization	Yes or No	Question 4 Comment
		requirements perhaps stand on their own as individual requirements?
Response: Thank you for your comment. **The drafting team agrees in principal and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
American Transmission Company, LLC		
CenterPoint Energy		
BGE	No	The VSLs are tied to the timetables set out in Requirements R1.2 through R1.4. As stated before, this unreasonably holds the registered entity hostage to the whims of a Transmission Operator or other entity who at best may have “no skin in the game” and at worst may have competing priorities.
Response: Thank you for your comment. **The time frames have been adjusted to allow for potential problems with outages. The new VSLs are based on the new time frames in the requirements.**		
Consumers Energy		
ITC	No	Answered No because of issues with meeting present time limit.
Response: Thank you for your comment. **The time frames have been adjusted to allow for more investigation if needed. The new VSLs are based on the new time frames in the requirements.**		
Wisconsin Electric		
Duke Energy	No	VSLs should be revised consistent with our comments on the requirements.
Response: Thank you for your comments.		

Organization	Yes or No	Question 4 Comment
The VSLs are based on the new time frames in the new requirements.		
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board	No	SUB's concern is that if entities are required to report non-events, and then fail to do so, they would be in violation of the standard, and incur a possible penalty based on a violation severity level/violation risk factor of not reporting a misoperation. SUB is concerned that applying "High" VSLs and VRFs for failure to report non-events seems less about promoting reliability and points more toward a mechanism to collect penalty funds.
Response: Thank you for your comment. **The drafting team agrees in principle and the requirements have been separated to provide for more granularity. The VRFs and VSLs have been assigned accordingly.**		
BC Hydro		

5. The team has included Measures and Data Retention with this posting. Do you agree with the assignments that have been made? If not, please provide specific suggestions for improvement.

Summary Consideration:

Several commenters proposed to make the reporting template the official document for compliance. The SDT responded that Attachment 1 reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed to identify those that are Misoperations.

Several commenters expressed concern that the use of the word "written" does not allow for electronic data retention. The SDT redrafted the standard and the word "written" has been removed. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.

Several commenters expressed concern that the data retention period should not exceed the audit cycle. The SDT redrafted the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C, CMEP Section 3.1.4.2, which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended, and ending with the End Date for the Compliance Audit.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	1. Measure M2 requires additional documentation with no additional value. 2. Why would the "Quarterly Misoperations Reporting Data" table, in the format of the template provided with the standard, not be sufficient?
Response: Thank you for your comments. **1. The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure the compliance with the requirements.** **2. The "Quarterly Misoperations Reporting Data" table reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed to identify those that are Misoperations.**		

Organization	Yes or No	Question 5 Comment
Public Service Enterprise Group Company	No	We recommend that R1.5, which is referenced in M6 and M7, be eliminated because the progress reporting of each CAP, including its completion, is sufficiently addressed in Section 1.4 (of the Compliance Monitoring Process section of the standard) which states "Each responsible entity will include the status of its Misoperation CAPS or action plans developed until these CAPs or action plans are reported complete." We note that Attachment 1, which defines the format of these periodic reports, allows an entity to enter CAP progress data beginning at the bottom of page 3 with corrective actions taken, and continuing on page 4 where CAP target and actual completion dates are reported. Evidence supporting those periodic reports could be requested as needed, and if necessary, the retention of evidence supporting the reports can be addressed in Section 1.2 of the Compliance Monitoring Process. With the elimination of R1.5, M6 and M7 can also be eliminated.
Response: Thank you for your comment. **The SDT revised the standard. Requirement R4 now necessitates the completion of CAPs or action plans. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan.**		
Hydro One	No	1. Measure M2 requires additional documentation with no additional value. 2. Why would the "Quarterly Misoperations Reporting Data" table, in the format of the template provided with the standard, not be sufficient?
Response: Thank you for your comments. **1. The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure the compliance with the requirements.** **2. The "Quarterly Misoperations Reporting Data" table reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed to identify those that are Misoperations.**		
Tri-State Generation and Transmission Ass'n - System	No	Measure M2 (and possibly others) is a Requirement. It does not improve reliability, but only provides for additional record keeping for compliance documentation.

Organization	Yes or No	Question 5 Comment
Protection		
Response: Thank you for your comment. **The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure compliance with the requirements.**		
FirstEnergy	No	Measure M7 - Since M6 already requires evidence to show implementation of the CAP as required by R1 subpart 1.5, we do not see the need to have M7 and suggest it be removed.
Response: Thank you for your comment. **The SDT revised the standard. Requirement R4 now necessitates the completion of CAPs or action plans. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan. Measure M7 has been eliminated.**		
Pepco Holdings Inc Affiliates	No	The data retention provisions within the proposed standard seem reasonable. 1. However, there are concerns with several of the Measures.M2 - This measure should be re-written to state the entity shall "have evidence showing the dates of occurrence of all BES faults, associated protective system operations, and identified misoperations." The standard should not specify the format that this data should be in. Some companies retain this data in their internal database format, or write detailed reports for each operation (both correct and incorrect). Specifying that a dated list be provided is unnecessary and non productive when other means of supplying the required evidence is available. 2. M4 & M5 - To avoid duplication of efforts and record keeping, the evidence required to satisfy these two measures should be included on the ERO spreadsheet. This way the review and feedback from the Compliance Monitor on the data supplied will be more timely than waiting for the next audit cycle, which may be years away. This would improve the overall objective of improving the thoroughness of the investigations and corrective action plans. Also, the ERO spreadsheet and this feedback from the Compliance Monitor could be used as evidence of compliance during a formal audit.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. **1. The SDT revised the standard. Measure M1 (old M2) now states that the examples of acceptable evidence "includes but is not limited to…" so it allows for flexibility in satisfying compliance with the requirement. This documentation is needed to ensure compliance with the requirements.** **2. The SDT revised the standard and Measure M4 now includes providing evidence for both the implementation and completion of CAPs and action plans. The data in the spreadsheet may not be complete evidence of implementing or completing a CAP or action plan.**		
Southern Company Generation	No	1. As noted above in the comment with Question 2, the Measures along with the Requirements should be phrased to establish the objectives only and not in the details of one possible way to accomplished the objectives. 2. Regarding the data (evidence) retention, what is the basis for the six year retention requirement? The data retention period needs to be the time elapsed since the previous audit unless directed by a Compliance Enforcement Authority to retain specific evidence for longer periods as part of an investigation. The Additional Compliance Information section (1.4) contains a requirement for the TO/GO/DP to report to the RE. This should be in the main requirement section of the standard. Also, to eliminate PRC-003, a requirement is needed for the RE to gather the region's records and report to NERC.
Response: Thank you for your comments. **1. The SDT revised the standard. The measures provide examples of evidence that can be used to demonstrate compliance with the requirements.** **2. The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 and requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	1. We would like to see in section M2 BES faults added here as well to clarify that we are talking about BES rather than any fault.

Organization	Yes or No	Question 5 Comment
		2. Should data retention follow the audit cycle for each applicable entity? I.E. if your audit cycle was three years then it would be three years and if it was six years then it would be the six years mentioned.
Response: Thank you for your comments. **1. The SDT removed BES Faults from the requirements because review of all Protection System operations would include Faults. The term BES is not used in the individual requirements and measures because the standard's Applicability section 4.2.1 states "Protection Systems for Facilities that are part of the BES."** **2. The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 and requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
MRO's NERC Standards Review Forum	No	1. The measures are incorrect and must be changed to match the modified requirements. However, the measures are reasonable and could be translated into requirements R1 - R6 or R1 - R7 with corresponding measures. 2. The data retention is incorrect. The data retention should state that data should be retained back to the last audit period. If not, the drafting team should provide the reliability reasoning why an entity with an audit cycle faster than six years would need to retain data past its last audit cycle. In 1.2 Evidence Retention, the "and Measures M1, M2, M3, M4, M5, M6, and M7" reference should be deleted.
Response: Thank you for your comments. **1. The SDT revised the standard. Each new requirement now has an associated measure.** **2. The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
Electric Market Policy	No	Recommend removing Measures from (B.) and creating a separate section for Measures. (B.) should be changed to (B. Requirements) Also change to (C. Measures) (D. Compliance) (E. Regional Variances) (F. Interpretations) (G. Associated Documents) Suggest wording change as follows: C. MeasuresM1. The responsible entity shall have a current copy of its procedure for identifying and addressing Misoperations in accordance with Requirement R1.

Organization	Yes or No	Question 5 Comment
		M2. The responsible entity shall have documentation of Faults, BES Element operations, and identified Misoperations with their associated date of occurrence to demonstrate implementation of the processes related to Requirement R1, Part 1.1. M3. The responsible entity shall have documentation for each Misoperation investigation with their associated dates and either cause or where the cause of the Misoperation cannot be identified, any additional steps planned for identifying causes to demonstrate implementation of the processes related to Requirement R1, Part 1.2. M4. The responsible entity shall have documentation with associated dates of a CAP or an explanation of why there is no need to develop a CAP, for each Misoperation with an identified cause to demonstrate implementation of the processes related to Requirement R1, Part 1.3.M5. The responsible entity shall have documentation with associated dates that includes a work timetable for implementation or an explanation of why no further investigation or actions will be taken for each Misoperation without an identified cause to demonstrate implementation of the processes related to Requirement R1, Part 1.4. M6. The responsible entity shall have documentation with associated dates such as work management program records, work orders or other dated evidence, to demonstrate implementation of action plans related to Requirements R1, Part 1.5. M7. The responsible entity shall have documentation with associated dates that describes the manner in which the each CAP or action plan was completed to demonstrate compliance with the processes related to Requirements R1, Parts 1.5
Response: Thank you for your comments. **The SDT is following the NERC template for the new Results-based Standards where the requirements and associated measures are together rather than separated. The SDT has revised the draft standard.**		
Pacific Northwest Small Public Power Utility Comment Group	No	M6 and M7 appear to be duplicative. Please combine into a single measure, or more clearly state how they are different.
Response: Thank you for your comment. **The SDT revised the standard. Requirement R4 now necessitates the completion of CAPs or action plans. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan. Measure M7 has been eliminated.**		

Organization	Yes or No	Question 5 Comment
LG&E and KU Energy		
APM Members	No	M1 is not consistent with the NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. In that bulletin, NERC states that an entity may be held in violation of the requirement if it cannot produce previous versions of a procedure. Six years seems quite excessive for data retention. Three years should be sufficient. Six years appears to have been selected to match the audit cycle of the applicable functional entities. NERC contemplates that the data retention period may not be as long as the audit period in the NERC Compliance Process Bulletin #2011-001 issued on May 20, 2011. Thus, it is not necessary for the date retention period to match the audit cycle.
Response: Thank you for your comment. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
PPL Generation		
Florida Municipal Power Agency	No	see comments to Question 1
Bonneville Power Administration	No	1. BPA believes that under M1: Entities should not be required to provide documentation of the processes and procedures that they use to identify and address Misoperations. 2. M2 thru M7: BPA feels that the measures given are overly burdensome. Reading these measures would lead one to believe that NERC has an expert panel of protection engineers on standby, waiting to sift through the data provided for each misoperation, and give expert guidance to the industry. BPA feels that this is not accurate, as this NERC standard will only capture an overview of the number and types of Misoperations experienced in the industry. 3. BPA feels that the documentation requested will require many hours of work, and feels that the only review of it will be from an auditor whose only purpose is to make sure that it was accumulated. BPA feels that the burden of providing these detailed investigative reports and corrective action plans will result in less productive time for the individuals who

Organization	Yes or No	Question 5 Comment
		are the ones capable of solving the problems. BPA feels that only basic information, such as an elementary description of the misoperation, and a basic corrective action plan should be required. Lists of faults, investigative reports, work management program records, etc. seem to be unnecessary. If the experts at NERC need more information on a particular misoperation, they can always request it.
Response: Thank you for your comments. **1. The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure compliance with the requirements.** **2. Measures support requirements by identifying what evidence or types of evidence could be used to show that an entity is compliant with the requirement. The SDT revised the standard and each requirement now has an associated measure. The purpose of the draft standard is to identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.** **3. The SDT believes the requirements are necessary to achieve the stated purpose of the standard.**		
Western Area Power Administration	No	1. M2 calls for a list of faults, protection system operations, etc. Would be good to be able to just point to our outage database instead of having to create a separate list. We are creating a separate spreadsheet at this point. 2. Six years for evidence retention seems kind of long. We would suggest 3 years or one audit period.
Response: Thank you for your comments. **1. The SDT redrafted the standard. Measure M1 (old M2) now states that the examples of acceptable evidence "includes but is not limited to…" so it allows for flexibility in satisfying compliance with the requirement. This documentation is needed to ensure compliance with the requirements.** **2. The SDT redrafted the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		

Organization	Yes or No	Question 5 Comment
Westar Energy	No	Data retention should coincide with the audit cycle.
Response: Thank you for your comments. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
Georgia Transmission Corporation	No	PRC-018-1 R5 DME data retention for RRO events is 3 years. 3 years should be adequate considering data is now available in spreadsheet format.
Response: Thank you for your comments. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
PacifiCorp	Yes	
NextEra Energy, Inc.	Yes	
Southern Company		
Flathead Electric Cooperative, Inc.	Yes	
Green Country Energy	No	The term "written" keeps coming up and I feel it needs to be deleted since it has the connotation of a long hand "written" document and leaves no opportunity for an electronic format.
Response: Thank you for your comment. **The SDT revised the standard and the word "written" has been removed. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.**		

Organization	Yes or No	Question 5 Comment
Hydro-Quebec TransÃ ‰ nergie	Yes	
Ingleside Cogeneration LP	Yes	
Oncor Electric Delivery	Yes	
Private Citizen		
Consolidated Edison Co. of NY, Inc.	No	Measure M2 requires additional documentation with no additional value. Why would the "Quarterly Misoperations Reporting Data" table, in the format of the template provided with the standard, not be sufficient?
Response: Thank you for your comments. **The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure compliance with the requirements. The "Quarterly Misoperations Reporting Data" table reflects only identified Misoperations. It does not provide documentation that all Protection System operations have been reviewed to identify those that are Misoperations.**		
Orange and Rockland Utilities, Inc.		
PSE	Yes	
TransAlta	Yes	
Entergy Services		
GenOn Energy		

Organization	Yes or No	Question 5 Comment
Indiana Municipal Power Agency	No	In the previous two version of PRC-004, the data retention time was not six years. How does the SDT plan on making the implementation to the six year data retention when the previous data retention time was 12 months or until your CAP was completed? IMPA believes the previous data retention time requirement should be used on this version of PRC-004.
Response: Thank you for your comments. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		
Exelon	Yes	ComEd: On Measurement M3 & M4 with regards to a dated documentation, do these have to be captured in a system outside of a standard business application for the purpose of locking a tracking date?
Response: Thank you for your comments. **The SDT revised the standard. Measure M1 (old M2) now requires the Transmission Owner, Generation Owner, and Distribution Provider to have documentation of identified and reviewed Protection System operations as well as indicating the ones that were designated as Misoperations. This documentation is needed to ensure compliance with the requirements.**		
Manitoba Hydro	No	Manitoba Hydro suggests that the Evidence Retention period be 3 Calendar Years to align with the data retention required for audits. The standard drafting team has not provided justification for extending the Evidence Retention period to 6 Calendar Years and given that Misoperations will be reported quarterly, it is not clear why 6 Calendar Years of evidence would be required.
Response: Thank you for your comments. **The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.**		

Organization	Yes or No	Question 5 Comment
Tacoma Power	No	The distinction between M6 and M7 is unclear.
Response: Thank you for your comments. **The SDT revised the standard. Requirement R4 now necessitates the completion of CAPs or action plans. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan. Measure M7 has been eliminated.**		
Ameren	No	1. We believe that the Evidence Retention back to the most recent Compliance Audit is sufficient. The Regional Entity has access to all evidence during the Compliance Audit so it need not be retained after that. TO, GO, and DP are reporting Misoperations quarterly to the Regional Entity, so sufficient ongoing monitoring can occur. 2. Many measures require 'dated written lists'. We presently use an outage tracking database, which includes our correct operations and Misoperations. Are you requiring us to revise this software so that it automatically tracks date and time of entry of each pertinent item of this standard? Please provide some guidance or point us to what NERC accepts as an equivalent to a 'dated written list'. 3. In M, please remove 'each' as this in an extra word. There seems to be a few other grammatical errors in this sentence.
Response: Thank you for your comments. **1. The SDT revised the Evidence Retention section to follow the NERC Rules of Procedure, Appendix 4C CMEP Section 3.1.4.2 which requires that data or evidence to show compliance be retained for the period beginning the day after the prior audit ended and ending with the End Date for the Compliance Audit.** **2. The SDT revised the standard. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.** **3. The SDT revised the standard.**		
Utility Services, Inc.		
American Electric Power	No	Within M4 and M5, it is not clear what the meaning or intent is of "dated written declaration", or what it would constitute.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **The SDT revised the standard. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.**		
American Transmission Company, LLC	No	ATC is concerned that the measures defined in M2, M3 and M5 leave out the possibility of using a database to capture the data. Please replace the term "dated written" in the measures section with "dated records". This change allows for records stored in databases, generated from manufacturer programs as well as for written records.
Response: Thank you for your comment. **The SDT revised the standard. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.**		
CenterPoint Energy		
BGE	No	M2. Through M5 requires "written lists, written investigation reports, written declarations, and written action plans...." The intent here should simply be all protection system operations, with auditable investigations reports, and clearly documented action plans. In a modern world these can be accomplished in many ways... The use of the term "written" is archaic....
Response: Thank you for your comment. **The SDT revised the standard and the word "written" has been removed. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.**		
Consumers Energy		
ITC	No	Within M2 "Protection System operations" should not be included. Suggest changing this to "BES outages".
Response: Thank you for your comment. **The SDT revised the standard. Measure M1 (old M2) now states acceptable examples of evidence for the Transmission**		

Organization	Yes or No	Question 5 Comment
Owner, Generation Owner, and Distribution Provider to satisfy compliance with the requirement. To identify all Misoperations, all Protection System operations must be identified and reviewed with a systematic approach. Every Protection System operation is either a correct operation or a Misoperation. The review of correct operations may lead to the discovery of Misoperations (failure to trip). This documentation is needed to ensure compliance with the requirements. The term BES is not used in the individual requirements and measures because the standard's Applicability Section 4.2.1 states "Protection Systems for Facilities that are part of the BES."		
Wisconsin Electric	No	1. In M1 through M5, the adjective "written" list, report, etc should be removed since any such evidence may be electronic and not necessarily written on paper. 2. In M5, replace "work timetable" with "schedule". 3. M6 should be replaced by a simpler statement like, "The responsible entity shall have dated evidence, such as work management records or other evidence, to demonstrate completion of all plans required by R1.5." M7 is superfluous to M6 and should be removed.
Response: Thank you for your comments. **1. The SDT revised the standard and the word "written" has been removed. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements.** **2. The SDT used the term "timetable" to remain consistent with the definition of Correction Action Plan (CAP) in the NERC glossary.** **3. The SDT revised the standard. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan. Measure M7 has been eliminated.**		
Duke Energy	No	o M5 - delete this Measure associated with R1.4 consistent with our response to question #3 above. o M6 and M7 should be combined.
Response: Thank you for your comments. **The SDT revised the standard. Measure M4 now provides examples of acceptable evidence to demonstrate implementation and completion of any CAP or action plan.**		
Constellation Power Generation/Constellation		

Organization	Yes or No	Question 5 Comment
Energy Nuclear Group		
Springfield Utility Board		
BC Hydro		

6. The team has included the "Quarterly Misoperations Reporting Data" table and template, and the supporting reference document. Do you have any specific suggestions for improvement?

Summary Consideration:

The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".

Several commenters had concerns with the reporting form requiring TADS event ID's. The drafting team responded that correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809.

Several commenters pointed out inconsistencies between the new definition of Misoperation and the categories on the template and Attachment 1. The drafting team responded that the template (form) itself will not be a part of this standard. The language in the Misoperation Reporting Template will be revised by the Reliability Assessment and Performance Analysis group and will match the language approved for use in the revised standard PRC-004.

Several commenters had concerns with the number of cause codes on the template and Attachment 1. The drafting team responded that the NERC SPCS recommended six Cause Codes in the whitepaper "SPCS Input on Uniform Misoperations Reporting" (Table 2) based on current regional procedures. While adopting these six Cause Codes will require reporting more detail for some regions and less for others, the SPCS believes they strike a necessary balance between having enough Cause Codes to track meaningful trends in Protection System performance while avoiding confusion and inconsistency. In addition to these six codes, the Misoperation Reporting Template will include "Other/Explainable" and "Unknown/Unexplained".

Several commenters had concerns with clarifying how to handle reporting if no Misoperations have occurred. The drafting team responded that today each Region has its own reporting procedures and some do require notification or completion of a form to indicate that the entity has no Misoperation to report. The process of how this will be handled in the future is outside the scope of this drafting team.

One commenter had a concern with quarterly reporting requirements versus semi-annual. The drafting team responded that while some regions require semi-annual reporting today, on October 22, 2010 NERC's ERO Executive Management group endorsed an ERO-

RAPA recommendation to the regions to start the collection of data on a quarterly basis beginning in 2011. The 2009 SPCS assessment of PRC-003-1, PRC-004-1, and PRC-016-1 also endorsed quarterly reporting.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council		
Public Service Enterprise Group Company	Yes	1. See the previous comment in response to question 3 regarding semi-annual rather than quarterly reports. 2. In addition, the current format of the Excel file can be improved to make it more "user-friendly." We recommend that the information in Row 3 be converted into Excel "comments" and placed in Row 2. This will eliminate a row from viewing and allow the user to scroll down and still have the valuable information from Row 3 available in Row 2 if needed. In addition, adjusting the font size may allow for more columns to be viewed on one screen.
Response: Thank you for your comments. **1. While some regions require semi-annual reporting today, on October 22, 2010 NERC's ERO Executive Management group endorsed an ERO-RAPA recommendation to the regions to start the collection of data on a quarterly basis beginning in 2011. The 2009 SPCS assessment of PRC-003-1, PRC-004-1, and PRC-016-1 also endorsed quarterly reporting.** **2. The template (form) itself will not be a part of this standard.**		
Hydro One	No	
Tri-State Generation and Transmission Ass'n - System Protection	Yes	All columns that reference "TADS" should be removed. Protection engineers, who will be filing these reports, do not generally have access to the TADS information or filings. Much of the TADS information is not required quarterly so it may not even be available for submittal by the Protection staff. The Regional Entities can supply the TADS information after it is received by them.
Response: Thank you for your comment. **Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC**		

Organization	Yes or No	Question 6 Comment
Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, the TADS Reportable Outage = No and TADS Event ID(s) = N/A.		
FirstEnergy	Yes	We ask that it be clear within the standard (maybe a link in the standard) of where you can obtain this form used for quarterly updates.
Response: Thank you for your comment. **The template (form) itself will not be a part of this standard. Guidance for submitting the data will be provided by the Regional Entities or NERC.**		
Pepco Holdings Inc Affiliates	No	
Southern Company Generation	Yes	Eliminate the TADS columns Q, R, and S for generators as this code is meaningless for those entities.
Response: Thank you for your comment. **Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A.**		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	Yes	1. Attaching the TADS reference to this template could cause a non reporting for instances in which other entities actually report the TADS information and not the Misoperation. 2. There needs to be consistency with the excel sheet language and the standard itself. Under the definitions tab in the excel sheet the language isn't consistent with the

Organization	Yes or No	Question 6 Comment
		language in the standard itself.
Response: Thank you for your comments. 1. **Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A.** 2. **The template (form) itself will not be a part of this standard. The language in the Misoperation Reporting Template will be revised by the Reliability Assessment and Performance Analysis group.**		
MRO's NERC Standards Review Forum	Yes	This should be a requirement.
Response: Thank you for your comment. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".**		
Electric Market Policy	Yes	The following comments are related to the "Quarterly Misoperations Reporting Data" table and template: 1) The fields associated with TADS reporting appear to be outside the scope of this reliability standard as stated in the Purpose, therefore we do not agree with inclusion of TADS. 2) The form does not address "action plans" that would be developed in response to Requirement R1, Part 1.4.The form appears to be collecting additional information that goes beyond the Purpose of the standard, i.e., "Identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems." Specific information includes: Equipment Type; Facility Voltage (kV); Equipment Removed from Service; Relay Technology.

Organization	Yes or No	Question 6 Comment
		The following comments are related to the reference document, SPCS Input on Uniform Misoperations Reporting: 1) The document and template appear to be focused on collecting data for the purpose of reliability metric ALR4-1. This additional data collection is outside the scope of draft standard PRC-004-3 and the proposed requirements stated in the associated Standards Authorization Request (SAR). Therefore, Dominion recommends that only data necessary to address the standard requirements be collected. 2) Section 3 Misoperation Categories 1st Paragraph and Table 1 Misoperations Categories are not consistent with the categories contained in PRC-004-3. Suggest revising document to include the five categories contained in the draft standard. 3) Section 4 Cause Codes 1st paragrah suggests there are six cause codes in Table 2 which is inconsistent with Table 2 that shows seven cause codes. Suggest revising document in the 1st paragraph to say seven cause codes. 4) Template is hard to use because of the number of horizontal columns of data being requested. The number of fields of data being requested seems to be excessive. Any way to reduce the number of fields? 5) Facility Name (Location of Misoperation) field - IS this asking for location that caused the misoperation or the location of the breakers that operated? For example, when a failed carrier set at Station A causes the other terminal at station B to misoperate during a fault, do I enter Station A or Station B? 6) Equipment Type field - includes Dynamic VAR Systems but does not include Static VAR Systems (SVC for example). Should SVC be included? 7) Facility Voltage (kV) field - includes a choice of <100. Since the BES is defined as those elements >100 KV, this choice should be deleted. 8) For a unit connected generating unit with a 230 kV - 13.8 KV GSU and the 230KV generator output breakers trip when the unit trips, what KV do I enter? For a generator that has a 13.8 KV output breaker and a 230 kV - 13.8 kV GSU and the 13.8 KV breaker trips when the unit trips, what KV do I enter? 9) Equipment Removed from Service field - Isn't this the same information as the Equipment Name field? In the example provided there is no difference in what was entered. The Field Value info apparently limits this to Circuits, Transformers, Buses (and also breakers if the

Organization	Yes or No	Question 6 Comment
		breaker is the only element to trip). Does "Circuits" mean the same as Lines? Suggest Circuits be changed to Lines. Do we include generators? Note that TADS does not require reporting of breaker trips unless a Line or Transformer is affected, shouldn't Misoperations do the same? Note that TADS does not include reporting of Buses or many of the other Equipment Types mentioned in the Misoperations template. Do you want all Equipment Types listed or only Lines and Transformers? We suggest it be limited to one entry focusing on the Equipment (ie Element) that misoperated. 10) Event Description field - The title using the word Event seems to entail the overall event which could include correct operations and Misoperations, and the description indicates a brief description of the event and a detailed misoperation description. But the example data seems to indicate only a misoperation description. Can you include as an example description that has a problem on one line and another line over trips. 11) Causes(s) of Misoperation field - Field is named Cause but description asks for root cause(s). Are you looking for one or are you asking for more than one to be entered? Suggest that the word "root" be removed from description. TADS and other industry benchmarking use Cause not root cause. Suggest that only one choice be allowed for entry. 12) Protection Systems/Components that Misoperate field - Is this redundant since you have asked for a detailed description of the Misoperation in the Event Description field? 13) Relay Technology field - suggest that only one choice be allowed. What do you enter if no entry is required (leave it blank or indicate n/a)? We suggest blank. 14) Actual CAP Completion Date field - Change name to CAP Actual Completion Date be consistent with the CAP Target Completion Date field. 15) If the SDT ultimately decides to use one or more of the availability reporting systems (TADS or GADS or DADS), we have the following questions/comments: a. Cause Code field - What do you enter if no entry is required (leave it blank or indicate n/a)? We suggest blank. b. Event ID(s) field - What do you enter if no entry is required (leave it blank or indicate n/a)? We suggest blank.

Response: Thank you for your comments.

In regards to comments related to the Misoperation Reporting Template:

1) Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by

Organization	Yes or No	Question 6 Comment
NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A. **2) Thanks for this comment on how to report action plans when cause is not identified. The drafting team made modifications to the reference document "Quarterly Misoperations Reporting Data.** **In regards to comments related to the reference document "SPCS Input on Uniform Misoperations Reporting"** **1) The SAR identified misoperation data currently collected is not usable to establish a consistent metric for measuring Protection System performance and to establish a standard with uniform applicability and clarifying reporting requirements.** **2-3) The SDT cannot revise the SPCS whitepaper.** **4-15) These comments are directed at revising and clarifying the Misoperation Reporting Template. The drafting team appreciates all these comments and will refer them to the SPCS and the ERO RAPA group for their use.**		
Pacific Northwest Small Public Power Utility Comment Group	Yes	The misoperation category dropdown list does not match the five categories of the definition.
Response: Thank you for your comment and pointing out this inconsistency. **The template (form) itself will not be a part of this standard. The language in the Misoperation Reporting Template will be revised by the Reliability Assessment and Performance Analysis group.**		
LG&E and KU Energy	Yes	This seems to be the Excel Spreadsheet that NERC has already placed in force effective with 2Q 2011 reporting of Misoperations
Response: Thank you for your comment. **The Misoperation Reporting Template (Excel) is the same as the spreadsheet proposed by the ERO-RAPA group which was reviewed and agreed by the NERC SPCS (with comments) in the whitepaper "SPCS Input on Uniform Misoperations Reporting."**		

Organization	Yes or No	Question 6 Comment
APM Members		
PPL Generation		
Florida Municipal Power Agency	No	see comments to Question 1.
Response: Thank you for your comment.		
Bonneville Power Administration	Yes	1. If NERC really needs the information in the this table, then BPA will support it. However, the way that TADS event IDs are assigned, doesn't easily align with relay misoperations and may be cumbersome and BPA questions whether or not it is be necessary to provide the TADS event ID. 2. BPA suggests that the quarterly reporting requirement given under Section 1.4, Additional Compliance Information is misplaced and suggests that it be given as "ONE" of the requirements. BPA feels that the quarterly reporting table should be all the information that is required, and suggests that measures M1 thru M7 should be removed.
Response: Thank you for your comments. 1. **Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. The TADS Event ID Code is normally created by the Transmission Owner and they should be available to System Protection. If the TADS Event ID Code is not available at the time of the report, the column should be left blank and populated later either by the Regional Entity or the Transmission Owner. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A.** 2. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".**		

Organization	Yes or No	Question 6 Comment
Western Area Power Administration	No	
Westar Energy	Yes	Consistency between the Standard requirements and the 'Quarterly Misoperations Reporting Data' table and template must be ensured.
Response: Thank you for your comment and pointing out this inconsistency. **The drafting team will coordinate with the SPCS and the ERO RAPA group to ensure consistency.**		
Georgia Transmission Corporation	Yes	Spreadsheets make terrible flat databases. Is this spreadsheet wiped clean each quarter or do incomplete CAPs carry over to the next quarter? What is the procedure to have a field modified if the normal "pull down" selection is not adequate?
Response: Thank you for your comment. **The Misoperation Reporting Template (Excel) is the same as the spreadsheet proposed by the ERO-RAPA group which was reviewed and agreed by the NERC SPCS (with comments) in the whitepaper "SPCS Input on Uniform Misoperations Reporting". Follow-up detail for incomplete CAPS will be included on the next quarterly report with the field "Resubmittal Check" = Yes.**		
PacifiCorp		No comments.
NextEra Energy, Inc.		If a misoperation has multiple events before a root cause can be determined, then there should be one line item with multiple events, not multiple Misoperations.
Response: Thank you for your comment. **Correlating the Protection System Misoperation to a TADS event is needed to determine Metric ALR4-1 developed by NERC Operating and Planning Committees under NERC's Rules of Procedure Section 809. If a relay has misoperated multiple times before a cause can be determined, the Misoperation Reporting Form will require multiple entries as there will be multiple TADS outages. In this case each line may have the same Operation Category Code, Cause Code, and CAP, etc.**		
Southern Company		

Organization	Yes or No	Question 6 Comment
Flathead Electric Cooperative, Inc.	Yes	Need to make it clear that if there are no Misoperations no report is required.
Response: Thank you for your comment. **Today each Region has its own reporting procedures and some do require notification or completion of a form to indicate that the entity has no Misoperation to report. The process of how this will be handled in the future is outside the scope of this drafting team.**		
Green Country Energy	No	
Hydro-Quebec TransÃ ‰ nergie	Yes	
Ingleside Cogeneration LP		There needs to be a tight correlation with the Misoperation categories and cause codes introduced in the RAPA reporting template. Since those codes are already acceptable to NERC, it provides a technically sound starting point for a Misoperation investigation. If the RAPA team accumulates enough data to justify another cause code or provide further examples, than they can control it at one place. Ingleside Cogeneration believes that this is the only way that reporting needs can be managed properly. If guidance is not provided in PRC-004-3, then regional differences will continue to crop up - with unique data requirements and reporting templates.
Response: Thank you for your comment. **The NERC SPCS recommended six Cause Codes in the whitepaper "SPCS Input on Uniform Misoperations Reporting" (Table 2) based on current regional procedures. While adopting these six Cause Codes will require reporting more detail for some regions and less for others, the SPCS believes they strike a necessary balance between having enough Cause Codes to track meaningful trends in Protection System performance while avoiding confusion and inconsistency. In addition to these six codes, the Misoperation Reporting Template will include "Unknown/Unexplained" for cases where causes were not identified and properly documented.**		
Oncor Electric Delivery	No	
Private Citizen		

Organization	Yes or No	Question 6 Comment
Consolidated Edison Co. of NY, Inc.		
Orange and Rockland Utilities, Inc.		None
PSE	Yes	We have created an MS Access database to track all misoperation information starting in 2011. An export file is created in the format of the WECC spreadsheet to meet your requirements. We feel that the MS Access database offers several advantages in terms of the ability to sort records in many ways, offering a historical view of Misoperations that will span multiple quarters and years, and still offers all of the "pull down" choices related to definitions and codes.
Response: Thank you for your comment. **Today each Region has its own reporting procedures. The process of how this will be handled in the future is outside the scope of this drafting team.**		
TransAlta		
Entergy Services	Yes	1. The present template does not contain enough cause options. Additional granularity is needed to identify misoperation trends and to provide better focus on potential areas of improvement. For example, selecting AC failure as a misoperation cause which was due to rodent damage, or a relay failure cause due to a leaky roof, doesn't provide cause information which would be useful to determine whether we are experiencing actual equipment problems or some other unrelated problem. 2. Also, add a "No Problem Found" cause, to address those rare evolving type scenarios which would challenge even the best relay(s) and schemes, and where we actually know what happened, but there is no reasonable corrective action to prevent it from reoccurring.
Response: Thank you for your comment. **1. The NERC SPCS recommended six Cause Codes in the whitepaper "SPCS Input on Uniform Misoperations Reporting" (Table 2) based on current regional procedures. While adopting these six Cause Codes will require reporting more detail**		

Organization	Yes or No	Question 6 Comment
for some regions and less for others, the SPCS believes they strike a necessary balance between having enough Cause Codes to track meaningful trends in Protection System performance while avoiding confusion and inconsistency. **2. The SDT is recommending the addition of another Cause Code "Other/Explainable" – for events that are explainable but do not fit into the existing Cause Codes. This would require explanation of the cause in the Event Description field, and if no CAP is proposed, an explanation of why it is not required. These types of Misoperations could be the result of multiple contingency events.**		
GenOn Energy		
Indiana Municipal Power Agency	Yes	1. IMPA does not agree with the proposed definition of "Misoperation" and feels that the selections under Misoperation Category are broad and far reaching and will result in the vast majority of operations being termed "Misoperation". 2. In addition the definitions listed in the Definition Tab under the Cause(s) of Misoperation include equipment not covered under other Reliability Standards, such as Telco errors. These Causes need to be reviewed and modified to include only equipment covered by other Reliability Standards.
Response: Thank you for your comment. **1. The SDT disagrees that most operations will be classified as Misoperations. The definition was enhanced to add specificity. The selections under the Misoperation Category in the template will be expanded to accommodate the new definition of Misoperation.** **2. All components of a Protection System are considered in this standard regardless of ownership.**		
Exelon	Yes	Column Q, "Is this a TADs reportable outage", should have NA as an option with a footnote or some acknowledgement that generators do not report or participate in the TADs system. Exelon Nuclear: Column Q should have an "N/A" or and "unknown" field as a selectable option. GO/GOPs do not report or participate in the TADs system.
Response: Thank you for your comment. **If the misoperation involves a generator, the TADS Reportable Outage = No and TADS Event ID(s) = N/A.**		
Manitoba Hydro	Yes	In Column M (Misoperation Category) of the spreadsheet, only 4 Misoperation types are

Organization	Yes or No	Question 6 Comment
		provided for selection - Failure to Trip, Slow Trip, Unnecessary Trip - During Fault, and Unnecessary Trip - Other than Fault. To be consistent with the proposed definition, Failure to Trip should be replaced with Failure to Trip - During Fault, and Failure to Trip - Other than Fault.
Response: Thank you for your comment and pointing out this inconsistency. **The Misoperation Category drop down list in the Misoperation Reporting Template will match the list of Misoperation definitions.**		
Tacoma Power		None
Ameren	Yes	1) For Time Zone use Prevailing Time, e.g. CPT for Central Prevailing Time because that's what EMS systems provide. The switch to Daylight Savings time is simultaneous. 2) Require GO to use their GSU high side voltage for Facility Voltage, rather than the generator voltage which will always be <100 as the Facility Voltage.
Response: Thank you for your comments. **1) Not all utilities EMS switch to Daylight Savings Time, so indicating which Zone the Time is reported is required. Since cities and towns within time zones don't universally switch to daylight savings time, "Prevailing Time" would take on different meanings.** **2) In cases where the generator trips the high side GSU circuit breaker, the Misoperations Reporting Template specifies using the transformer high side voltage for the Facility voltage. In cases where the generator only trips it own unit circuit breaker, it is acceptable to use the generator voltage.**		
Utility Services, Inc.		
American Electric Power	No	
American Transmission Company, LLC	Yes	1. In the supporting document "SPCS Input on Uniform Misoperations Reporting":The Misoperations Categories include Slow trip (i.e., slower than required to meet TPL requirements). The parenthetical should be removed. Using the criteria of being slower than TPL standards, could be used as a loop hole.

Organization	Yes or No	Question 6 Comment
		2. The Cause Code Description for As-left personnel error should be improved by adding a description to make it clear that human error due to ongoing testing is not included. ATC believes the intent is to include only those items when the technician has left the substation in an unwanted state.
Response: Thank you for your comments. **1. In many cases high speed protection is installed as part of the utilities standard practice without having the need for high speed protection to meeting TPL requirements. A slow trip of this protection system would not negatively impact the BES, so it does not need to be reported.** **2. The Misoperations Reporting Template has a "Definition" tab with detailed definitions for the Cause Codes. It clarifies the As-left Personnel Error category as things left following maintenance or construction.**		
CenterPoint Energy		
BGE	Yes	The Application Guidelines need to be incorporated into the standard or specifically called out as a binding attachment to the standard.
Response: Thank you for your comment. **The ERO-RAPA group has indicated it plans to incorporate approved changes to the reference document titled "Quarterly Misoperations Reporting Data/Fields" into the Quarterly Misoperations Reporting Template. The reference document will be posted concurrently with the draft standard.**		
Consumers Energy	Yes	The Misoperation Category descriptions in the reporting template should match the wording of the proposed Misoperation definition as closely as possible.
Response: Thank you for your comment and pointing out this inconsistency. **The Misoperation Category drop down list in the Misoperation Reporting Template will match the list of Misoperation definitions.**		
ITC	Yes	Misoperation reports can be quite lengthy to provide the needed details. Because there can be significant information for an adequate report a spreadsheet is not the best way to collect and distribute this data. Higher level software applications should be used.

Organization	Yes or No	Question 6 Comment
Response: Thanks for your comment. **The Misoperation Reporting Template (Excel) is the same as the spreadsheet proposed by the ERO-RAPA group which was reviewed and agreed by the NERC SPCS (with comments) in the whitepaper "SPCS Input on Uniform Misoperations Reporting". If additional significant information is required, most Regional Entities provide the opportunity to attach additional documentation when submitting misoperation data. Today each Region has its own reporting procedures to report Misoperations. The process of how this will be handled in the future is outside the scope of this drafting team.**		
Wisconsin Electric		
Duke Energy	Yes	1. TADS transmission data may not be accessible to generators, and generator data may not be reported in TADS. 2. Need to add a 100 kV option on the template (column J).
Response: Thank you for your comments. **1. If the misoperation involves a generator, in most cases the TADS Reportable Outage = No and TADS Event ID(s) = N/A.** **2. The template has been modified and now includes a 100 kV option.**		
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board	Yes	1) Under "Applicability" in PRC-004-3, SUB recommends that the language lists Functional Entities (TO, GO, DP) who own the following Facilities (Protection Systems, SPS). The current version of the PRC-004-3 draft lists Functional Entities and Facilities as separate applicability. 2) SUB would ask for PRC-004-3 to clarify whether or not Functional Entities would be required to submit a quarterly report if they do not have any Misoperations occur during the quarter. SUB's concern is that if entities are required to report non-events, and then fail to do so, they would be in violation of the standard, and incur a possible penalty based on a violation severity level/violation risk factor of not reporting a misoperation. SUB is concerned that applying "High" VSLs and VRFs for failure to report non-events seems less about promoting reliability and points more toward a mechanism to collect

Organization	Yes or No	Question 6 Comment
		penalty funds.
Response: Thank you for your comments. **2. 1. The Applicability should be read as a logical 'and' statement. For example, if you are a Distribution Provider and own Protection Systems that are a part of the BES, then the standard is applicable. If you are a Distribution Provider and do not own Protection Systems that are a part of the BES, then the standard is not applicable.** **3. 2. Today each Region has its own reporting procedures and some do require notification or completion of a form to indicate that the entity has no Misoperation to report. The process of how this will be handled in the future is outside the scope of this drafting team.**		
BC Hydro		

7. If you are aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement please identify the conflict here.

Summary Consideration:

Several comments were received on various possible conflicts, including possible conflicts with other NERC standards, Section 1600 data requests, Section 215 of the Federal Power Act, and NRC regulations. In all of these cases, the drafting team reviewed the issues cited and feels that no conflict exists.

In response to one comment, the drafting team modified the Background statement to better reflect the interaction between this standard and the WECC regional Misoperations reporting standard.

Organization	Yes or No	Question 7 Comment
Northeast Power Coordinating Council		
Public Service Enterprise Group Company		
Hydro One	No	
Tri-State Generation and Transmission Ass'n - System Protection	No	None
Response: Thank you for your comment.		
FirstEnergy	No	Not aware of any at this time.
Response: Thank you for your comment.		
Pepco Holdings Inc Affiliates	No	

Organization	Yes or No	Question 7 Comment
Southern Company Generation		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team	No	
MRO's NERC Standards Review Forum	Yes	Where does PRC-009 (new PRC-006) & PRC-020 overlap or are they in conflict with this standard?
Response: Thank you for your comment. **The misoperation of Underfrequency equipment applied on the BES is covered by this standard. There is no conflict with PRC-009-0 and PRC-006-1 as they deal with Underfrequency equipment performance only during a legitimate Underfrequency Load-shedding event. There is no conflict with PRC-020 as it deals with Undervoltage Load-shedding which is specifically excluded from this standard.**		
Electric Market Policy	Yes	Conflict: Collection of additional data pursuant to Section 1600 of NERC's Rules of Procedure, such as TADS information, does not belong in a NERC Reliability Standard.
Response: Thank you for your comment. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".**		
Pacific Northwest Small Public Power Utility Comment Group	Yes	Conflict: Section 215 of the Federal Power Act. At least one regional entity is consistently applying PRC-004-1 to distribution systems in violation of the FPA. Version 3 adds nothing to limit or clarify the extent of the standard's reach.

Organization	Yes or No	Question 7 Comment
Response: Thank you for your comment. **There is no conflict between Section 215 of the Federal Power Act and this standard. This standard is for "Protection Systems for Facilities that are part of the BES" as stated in the Applicability section.**		
LG&E and KU Energy		
APM Members		
PPL Generation		
Florida Municipal Power Agency	No	see comments to Question 1
Response: Thank you for your comment.		
Bonneville Power Administration	No	BPA feels that in regards to the final paragraph of Section 5, Background, states that with regard to the WECC regional misoperation standard (PRC-004-WECC-1), complying with the more stringent standard will ensure compliance with the less stringent as well. BPA feels that this is not correct because the two standards have different requirements, and will require different actions to be in compliance with both. BPA believes that it would be helpful if WECC would rescind PRC-004-WECC-1.BPA asks, "Will the regional criterion, such as PRC-003-WECC-CRT-1 be rescinded?"
Response: Thank you for your comment. **The drafting team revised the Background section of the draft standard that discusses the WECC Regional Reliability Standard. PRC-004-WECC-1 and the regional criteria will not be rescinded by this drafting team.**		
Western Area Power Administration		
Westar Energy		

Organization	Yes or No	Question 7 Comment
Georgia Transmission Corporation	No	
PacifiCorp		No comments.
Response: Thank you for your comment.		
NextEra Energy, Inc.		
Southern Company		
Flathead Electric Cooperative, Inc.	Yes	You can't require the quarterly reporting of a non-event. Reporting should only be required if there is an actual BES Misoperation, no null reports.
Response: Thank you for your comment. **Today each Region has its own reporting procedures and some do require notification or completion of a form to indicate that the entity has no Misoperation to report. The process of how this will be handled in the future is yet to be determined.**		
Green Country Energy	No	
Hydro-Quebec TransÃ ‰ nergie	No	
Ingleside Cogeneration LP	No	
Oncor Electric Delivery	No	
Private Citizen	No	
Consolidated Edison Co. of NY, Inc.		
Orange and Rockland		None

Organization	Yes or No	Question 7 Comment
Utilities, Inc.		
Response: Thank you for your comment.		
PSE	No	
TransAlta		
Entergy Services		
GenOn Energy	No	
Indiana Municipal Power Agency		no comment
Response: Thank you for your comment.		
Exelon	No	
Manitoba Hydro	Yes	1. A number of Canadian Entities have the BES defined within their provincial legislation. This may introduce differences between the Protection System elements that are included in the BES according to provincial legislation and the NERC definition. This may impact the Protection System Misoperations that are reported. 2. As well, since Canadian Entities are not under FERC jurisdiction, the effective date of PRC-004-3 and the associated Misoperation reporting requirements may differ for Canadian entities and entities under FERC jurisdiction.
Response: Thank you for your comments. **1. The standard is applicable to BES Facilities; therefore, the applicability of the standard depends on the individual jurisdiction's definition of BES.** **2. The standard will become effective according to the applicable regulatory approval and its associated Implementation Plan.**		

Organization	Yes or No	Question 7 Comment
Tacoma Power		None
Ameren		
Utility Services, Inc.		
American Electric Power		AEP is not aware of any conflicts between the proposed standard and any regulatory function, rule, order, tariff, rate schedule, legislative requirement, or agreement, however, the definitions and reporting requirements for this standard would potentially be quite different from those required an RTO. This would not only produce duplication of efforts, but would also result in conflicting metrics.
Response: Thank you for your comment. **NERC does not regulate RTO requirements.**		
American Transmission Company, LLC		
CenterPoint Energy		
BGE	No	No comment.
Response: Thank you for your comment.		
Consumers Energy		
ITC		
Wisconsin Electric		
Duke Energy	No	
Constellation Power	Yes	Nuclear GO/GOPs have an existing Corrective Action Program that is required by 10 CFR

Organization	Yes or No	Question 7 Comment
Generation/Constellation Energy Nuclear Group		50 Appendix B Criterion XVI (quoted below). This regulatory requirement and associated mandatory implementation of a Corrective Action Program by a Nuclear GO/GOP fully envelopes the intent of the draft revision to PRC-004. An additional "procedure" to identify and address all Protection System Misoperations with set timelines and attributes is not necessary."XVI. Corrective Action Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management."
Response: Thank you for your comment. **The requirement(s) you cite cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC.**		
Springfield Utility Board		
BC Hydro		

8. If you are aware of the need for a regional variance or business practice that should be considered with this phase of the project, please identify it here.

Summary Consideration:

Most commenters argued that the regions – and WECC in particular – should not be allowed to have a regional standard for Misoperations reporting. The SDT responded that any Regional Entity is allowed to have regional standards that have more stringent requirements than the continent-wide standards. See NERC Rules of Procedure, Section 312.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council		
Public Service Enterprise Group Company		
Hydro One		
Tri-State Generation and Transmission Ass'n - System Protection		None.
Response: Thank you for your comment.		
FirstEnergy	Regional Variance:	This standard should be coordinated with regional reporting requirements to avoid duplication of efforts. For instance, RFC has Misoperations reporting requirements (per procedure titled "Reporting, Review, and Analysis of Protection System and Under Voltage Load Shedding (UVLS) Misoperations") for Protection systems AND UVLS system. Since this standard covers reporting of Protection system Misoperations, it should include a variance for the RFC region, or NERC should direct RFC to revise their reporting requirements to remove protection system Misoperations to avoid redundancy.

Organization	Yes or No	Question 8 Comment
Response: Thank you for your comment. **These regional reporting requirements will be coordinated with this standard. Regions may still require more stringent requirements than those in this standard or reporting for events not covered by this standard.**		
Pepco Holdings Inc Affiliates		
Southern Company Generation		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team		
MRO's NERC Standards Review Forum		
Electric Market Policy	Regional Variance:	Regional Variance: WECC Should consider the fact that WECC has Misoperation requirements that are not recognized by the other regions and the purpose of this standard is to standardize Misoperation documentation, reporting and definition of a Misoperation. Suggest no regional variances be allowed.
Response: Thank you for your comment. **Regions may still require more stringent requirements than those in this standard or reporting for events not covered by this standard.**		
Pacific Northwest Small Public Power Utility Comment Group		
LG&E and KU Energy		

Organization	Yes or No	Question 8 Comment
APM Members		
PPL Generation		
Florida Municipal Power Agency		see comments to Question 1.
Response: Thank you for your comment.		
Bonneville Power Administration		
Western Area Power Administration		
Westar Energy		
Georgia Transmission Corporation		
PacifiCorp		No comments.
Response: Thank you for your comment.		
NextEra Energy, Inc.		
Southern Company		
Flathead Electric Cooperative, Inc.		
Green Country Energy		

Organization	Yes or No	Question 8 Comment
Hydro-Quebec TransÃ ‰ nergie		
Ingleside Cogeneration LP		
Oncor Electric Delivery		
Private Citizen		
Consolidated Edison Co. of NY, Inc.		
Orange and Rockland Utilities, Inc.		None
Response: Thank you for your comment.		
PSE		
TransAlta		
Entergy Services		
GenOn Energy		
Indiana Municipal Power Agency		no comment
Response: Thank you for your comment.		
Exelon		
Manitoba Hydro		

Organization	Yes or No	Question 8 Comment
Tacoma Power		No more stringent regional variance should be applied for WECC.
Response: Thank you for your comment. **Regions may still require more stringent requirements than those in this standard or reporting for events not covered by this standard.**		
Ameren		
Utility Services, Inc.		
American Electric Power		We see no need for regional variances, whether for WECC or any other region.
Response: Thank you for your comment. **Regions may still require more stringent requirements than those in this standard or reporting for events not covered by this standard.**		
American Transmission Company, LLC		
CenterPoint Energy		
BGE		No comment.
Response: Thank you for your comment.		
Consumers Energy		
ITC		
Wisconsin Electric		
Duke Energy		

Organization	Yes or No	Question 8 Comment
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board		
BC Hydro		

9. If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.

Summary Consideration:

Numerous commenters were concerned about the prescriptive nature of the Guidelines and Technical Basis section of the standard. The SDT clarified that the Guidelines and Technical Basis section of the standard is included to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable.

Some commenters questioned the inclusion of SPS, RAS, UVLS, UFLS, and SPR in the draft standard. The SDT clarified that SPS and RAS Misoperations are excluded from PRC-004-3 because they will be addressed in the second phase of this project by another team. UVLS Misoperations are excluded because they are explicitly covered by PRC-022-1. UFLS Misoperations are included because not all aspects of UFLS Misoperations are explicitly covered by existing NERC standards. SPR Misoperations are not included because they are not currently part of the Protection System definition.

Several commenters were concerned about the implementation time being too short. The drafting team agreed and increased the implementation time for the new standard.

Some commenters questioned the purpose of the Background section. The SDT clarified that the Background section of the standard is part of the new NERC results-based template that will be used for all NERC Reliability Standards.

A few commenters questioned which entity had the responsibility of reporting Misoperations at an interface. The SDT clarified that the owner of the Protection System component that misoperated is required to report the misoperation.

A number of commenters questioned the location of the Misoperations reporting within the compliance section of the standard. The drafting team consulted NERC staff and decided the compliance section is the appropriate place for Misoperations reporting.

A few commenters questioned whether operations occurring during generator synchronization would be covered under PRC-004-3. In the Guidelines and Technical Basis section of the standard, the drafting team explained that these types of operations are excluded because the generating unit is not synchronized and is isolated from the BES.

Organization	Yes or No	Question 9 Comment

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council	Yes	Although the inclusion of the Application Guidelines is generally helpful, care is needed not to override the judgment of the Protection System owner for setting and designing its relay protection systems, particularly regarding the bias towards security or dependability. For example, the 4th paragraph on Page 14 ("Where studies have...) seems unduly prescriptive.
Response: Thank you for your comment. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems. The Guidelines and Technical Basis section has been revised and the text referred to has been deleted.**		
Public Service Enterprise Group Company		
Hydro One	Yes	1. Although the inclusion of the Application Guideline is generally helpful, care is needed not to override the judgment of the Protection System owner for setting and designing its relay protection systems, particularly regarding the bias towards security or dependability. For example, the 4th paragraph on Page 14 ("Where studies have...) seems unduly prescriptive. 2. Also, we have concerns with the identified time lines in R1.2, R1.3 and R1.4. Is the intent of the requirement for the RE to initiate action within the specified time once the misoperation is identified? The identification of a misoperation may not occur for some time after the actual protection system operation as there can be a lag between an operation occurring and the analysis of that operation. Some Misoperations may be obvious but some others not so much. We think that more clarity is needed here.
Response: Thank you for your comments. **1. The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems. The Guidelines and Technical Basis section has been revised and the text referred to has been deleted.**		

Organization	Yes or No	Question 9 Comment
2. The standard has been revised. The entity has 120 days after the occurrence of the operation to determine whether or not it was a Misoperation. For each designated Misoperation, investigate and document the findings including whether or not a cause is identified.		
Tri-State Generation and Transmission Ass'n - System Protection	Yes	1. As stated earlier, we believe the requirements should be expanded to state what is required rather than putting requirements in the measures. At that point we would be in a better position to address our comments to the requirements. 2. We believe that UVLS and SPS/RAS should be included in this standard and then PRC-012, Requirements R1.6, R1.7, and PRC-016 can be eliminated. If the standard is not changed to include UVLS and SPS, why is UVLS excluded but not UFLS? 3. Corrective Action Plan is defined in the NERC Glossary of Terms. Requirement 1, Part 1.3 should not describe what should be included in the CAP.
Response: Thank you for your comments. **1. The drafting team revised the requirements and measures for clarity.** **2. Misoperation associated with SPS/RAS will be addressed in the second phase of this project: Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. The SAR for this project did not include modification of PRC-022-1 Under-Voltage Load Shedding Program Performance which covers Misoperations of UVLS. Presently, not all aspects of UFLS Misoperations are explicitly covered by existing NERC standards.** **3. The drafting team removed the additional details from Corrective Action Plan description.**		
FirstEnergy	Yes	1. R1 Subpart 1.5 - We would appreciate clarification on the following regarding what constitutes successful completion of the Corrective Action Plan: Given the scenario of a maintenance error that caused the operation of a protection system, we understand that per this standard, if this misoperation is reported, and the error was corrected per the reported corrective action plan, then the entity is compliant with the standard even if the human error occurs again on a separately reported misoperation incident. Please confirm this understanding. 2. Applicability Section - The proposed standard excludes SPS, RAS, and UVLS systems. However, we do not see an exclusion for UFLS. The standard should clarify whether or not UFLS are applicable. 3. Effective Date - We believe that the proposed 3 month implementation of PRC-004-3 is

Organization	Yes or No	Question 9 Comment
		much too short for an entity to be able to achieve auditable compliance because it may require changes to internal procedures and business unit awareness of the new standard. We suggest at least 6 months after regulatory approval.
Response: Thank you for your comments. **1. The definition of a Misoperation has been modified to exclude an operation related to on-site maintenance, testing, construction or commissioning activities. If an operation occurred after the on-site activity and was related to a maintenance error, then it would be a Misoperation. The entity develops a CAP with the intention of correcting the cause of the Misoperation. The entity is responsible for its system performance and it is to its benefit to quickly correct Misoperations and prevent future Misoperations of a similar nature. The CAP is complete once all of the identified actions have been performed. The recurrence of a similar Misoperation at the same location is not a PRC-004-3 violation; however, it is an indication of the ineffectiveness of the completed CAP. A new CAP will need to be developed to remedy the specific problem. The new CAP should consider why the previous CAP did not result in the avoidance of a future Misoperation.** **2. Presently, not all aspects of UFLS Misoperations are explicitly covered by existing NERC standards.** **3. The drafting team agreed and increased the implementation time for the new standard.**		
Pepco Holdings Inc Affiliates	Yes	1. Section 4.2.2 should be revised to read "Special Protection Systems (SPS), Remedial Action Schemes (RAS), Under Voltage and Under Frequency load shedding programs, and Sudden Pressure Relays (SPR) are excluded from this standard." There has been past confusion as to whether the misoperation of an Underfrequency relay, which is part of a regional load shedding program, is reportable under this standard. Excluding UFLS programs eliminates this confusion. Adding SPR to the exclusions will also eliminate confusion. 2. Also, as mentioned in Question #1 the qualifying comments in the "Application Guidelines" section associated with the five Categories of Protective System Misoperations should be included, either in the standard itself, or as part of the misoperation definition. Without these specific qualifications it is not possible to reach a uniform consensus on what constitutes a misoperation and what does not. 3. However, the remaining sections of the "Application Guidelines" appear to be either tutorial, or background, in nature and should not be part of the standard itself. 4. Compliance data submittal C1.4 requires a quarterly report (ERO spreadsheet) be

Organization	Yes or No	Question 9 Comment
		submitted within 60 calendar days following the end of each calendar quarter. However, as was pointed out repeatedly, due to the difficulty in obtaining outages it is highly unlikely that many misoperation investigations could be completed, or corrective action plans developed / implemented, within 60 days after a quarter ends (particularly for those events which occur late in the quarter). For instance, suppose a misoperation occurs in June (second quarter). Data submittal will be required 60 days after the quarter ends (August 31). However, outages to conduct the necessary diagnostic testing will not be available until mid to late September. Therefore in an attempt to improve the percentage of reported events where investigations are complete and causes determined, we would suggest requiring the data submittal 90 days following the end of each quarter. This additional delay in data submittal will not impact the reliability of the BES, since any protective system misoperation contributing to a major system disturbance is already being thoroughly reviewed / investigated under EOP-004 Disturbance Reporting Requirements. 5. Under Section C 1.4 Additional Compliance Information, there is a reporting requirement. This should be included as a specific requirement in Section B. If not included in Sec B, it could easily be missed by the applicable entity as a requirement.

Response: Thank you for your comments.

1. **UFLS Misoperations on the BES are not excluded from this standard because they are not covered by any existing NERC standards. The standard relies on the applicable FERC approved definition of Protection Systems which currently does not include Sudden Pressure Relays (SPRs).**
2. **The drafting team revised the definition of Misoperation in the draft standard.**
3. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems.**
4. **The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the results. The standard was further modified to allow a time period of 60 days to develop either; the corrective action plan when a cause was determined; or, an action plan of additional steps if the investigation failed to determine a cause. The requirement for data submission has been eliminated. The data submission time frame has been adjusted to 2 calendar months after the quarter.**

Organization	Yes or No	Question 9 Comment
5. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information".**		
Southern Company Generation	**Yes**	1) In 4.2.2, point to PRC-016 for SPS Misoperations. 2) In suggesting to use the objectives listed (on page 5 of the 09 Jun 2011 draft standard) as the recommended requirements in the comments to Question 2 above, the removal of "faults" from the first objective was intentional. Generator Owners are not advised of "all faults" and have no way of knowing of all faults. Our experience has been that some Protection System will ultimately operate whenever a Protection System Misoperation occurs, therefore the suggested R1 was written excluding "all faults". 3) Another reason for eliminating all of the time frames suggested by R1 (R1.2, R1.3, and R1.4) relates to the 60 day reporting requirement to regions. A misoperation can occur on the last day of the quarter which must be reported 60 days later. The R1 subsections above time frames overlap the 60 days for a misoperation occurring late in the quarter. The simplified requirements suggested eliminate this problem. 4) We disagree with the statement made in item 3 of the Guidelines and Technical Basis section (page 12) of the draft standard. If the system did not perform as it was intended to (designed to), then it is a misoperation. 5) It is unclear what the phrase "situations that challenge a Protection System" means on page 13, Part 1.1 of the draft standard. 6) The exhaustive description of an investigation (page 13 Part 1.2 paragraph) should only be required where a definitive cause is not identified. For those cases where the cause has been determined, only the bottom line needs to be formally documented. 7) Will the Guidelines and Technical Basis section of the draft standard (p 12-16) become part of the standard? It is not referenced in Section F Associated Documents (p 11). 8) Will the Background section (A5) be retained with the standard?

Organization	Yes or No	Question 9 Comment
		9) Are revisions to Corrective Action Plans allowed to facilitate handling contingencies?

Response: Thank you for your comments.

1. **It is not a good practice to reference other Reliability Standards within a standard because of the dynamic nature of standards development.**
2. **The drafting team revised the standard and 'Faults' have been removed as an initiating event. A Protection System operation of an interrupting device is now the initiating event for an investigation.**
3. **The time interval was restructured to allow the entity 120 days to determine if the Protection System operation was a Misoperation, investigate the Misoperation and document the results. The standard was further modified to allow a time period of 60 days to develop either; the Corrective Action Plan when a cause was determined; or, an action plan of additional steps if the investigation failed to determine a cause. The drafting team has retained Protection System Misoperation(s) reporting in Section C1.4 of the draft standard.**
4. **In many cases high speed protection is installed as part of the utilities standard practice without having the need for high speed protection to meeting TPL requirements. A slow trip of this protection system would not negatively impact the BES, so it does not need to be reported.**
5. **The drafting team revised the draft standard and has modified the Guidelines and Technical Basis section as well to reflect the new requirements.**
6. **The drafting team revised the draft standard and has modified the Guidelines and Technical Basis section as well to reflect the new requirements.**
7. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems. The Background section of the standard is part of the new NERC results-based template that will be used for all NERC Reliability Standards.**
8. **Yes.**
9. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**

Transmission Access Policy Study Group	Yes	We understand that the draft standard was drafted by a "rapid development team" rather than by a stakeholder Standard Drafting Team. This new rapid development team process should not displace or compromise the stakeholder process. TAPS supports the goal of developing better standards more efficiently. If NERC and Regional staff draft a standard

Organization	Yes or No	Question 9 Comment
		without the benefit of significant industry input, however, we could risk moving toward greater inefficiency and delay, because problems that could have been addressed informally in drafting will instead have to be addressed formally through comments and revisions. Instead, the rapid development team should develop only the SAR, with the drafting of the standard left to the Standard Drafting Team, advised by technical writers and attorneys as appropriate.
Response: Thank you for your comment.		
SPP Reliability Standards Development Team		1. Would like clarification on failures during the synchronization of a unit. Clear line to when the point of misoperation could occur. 2. Shouldn't under frequency load shed also be excluded to be addressed at a later date? 3. Under the applicability section shouldn't the wording have been kept from the last posting that it would be distribution provider that owns a BES protection system? 4. Under compliance section third line protection needs to be capitalized. 5. On the same line shall submit a quarterly report. Need to insert, "quarterly report for the previous quarter".
Response: Thank you for your comments. **1. The drafting team revised the draft standard, and the Guidelines and Technical Basis section of the standard includes an explanation regarding the synchronization of a unit.** **2. UFLS Misoperations are included because they are not covered by existing NERC standards.** **3. The Applicability should be read as a logical 'and' statement. For example, if you are a Distribution Provider and own Protection Systems that are a part of the BES, then the standard is applicable. If you are a Distribution Provider and do not own Protection Systems that are a part of the BES, then the standard is not applicable.** **4. Thank you for pointing this out.** **5. Thank you for your comment**		
MRO's NERC Standards Review Forum	Yes	1. Clearly exclude power plant trips when they aren't part of the BES as Misoperations. Trips can occur easily during synchronization and may not be a reliability problem. There are many mechanical issues related to a power plant that may result in an

Organization	Yes or No	Question 9 Comment
		electrical synchronization trip. It's best to avoid inadvertently requiring unnecessary work that won't benefit reliability by clearly excluding plants that are not connected to the BES or plants in the process of synchronizing to the BES. 2. Non-BES plants should all be excluded.
Response: Thank you for your comment. **1. In the Guidelines and Technical Basis section of the standard, the drafting team explained that these types of operations are excluded because the generating unit is not synchronized and is isolated from the BES.** **2. Non-BES connected plants are excluded from applicability to this standard due to the NERC Statement of Compliance Registry Criteria, Section III(c).**		
Electric Market Policy	Yes	Dominion offers the following comments: 1) The "Rationale for R1" suggest that this revision will afford "enhanced reporting and the development of performance metrics that indicate overall system health, as well as facilitate the sharing of 'lessons learned'." Dominion notes that both performance metrics and lessons learned are outside of the scope of this reliability standard. Additionally, NERC is developing an Event Analysis process (currently in field trial) that includes a lessons learned component. Suggest NERC review the current process of blending data collection for other purposes with compliance. 2) The "Guidelines and Technical Basis" section appears to contain language that one could interpret as expanding the Requirements. Suggest clearly noting that this section is guidance only and not intended for compliance. 3) Section (5. Background) should be removed from the standard. This has no relevance to the Requirements or Measures of the new standard. 4)PRC 003 had the Regional Entity as a Functional Entity under Applicability; previous versions of PRC 004 have the TO, GO and DP listed as the Functional Entities under Applicability. PRC004-3 Background states that "PRC 003-1 is not enforceable..." and "This represents a potential reliability gap". According to PRC 004-3, responsible entities are to report to the Regional entities quarterly, so why isn't the Regional Entity listed in the new standard as a Functional Entity? Is the objective to require the regions to submit the data collected to NERC?

Organization	Yes or No	Question 9 Comment
		5)(R1.5) does not allow for extending the CAP beyond the pre-determined timeline when system conditions will not allow for equipment removal, outages, or project schedule changes. There are circumstances where outages continue to move and schedules are adjusted due to operating conditions or limitations that are beyond the control of those developing a projected CAP work timetable. Timetables can be set but it is not unusual that later, when the work is to be performed, that system conditions dictate a change in the schedule. 6) In (C.1.4) the Regional Entity and ERO references require more emphasis by creating a separate section listing Regional Entity requirements. 7) In the Application Guidelines; the Misoperation Definitions (1 -5), could include better examples or "bulleted" examples. 8) Consider not switching to landscape in the middle of the document. If landscape must be used move Regional Variances, Interpretations, and Associated Documentation to a new page. 9) Need to revise "Guidelines and Technical Basis" section to include Slow trip - other than Fault

Response: Thank you for your comments.

1. **The drafting team retained Protection System Misoperation(s) reporting in Section C1.4 of the draft standard.**
2. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable**
3. **The Background section of the standard is part of the new NERC results-based template that will be used for all NERC Reliability Standards.**
4. **The Regional Entities can no longer be applicable functional entities in a Reliability Standard. The drafting team retained Protection System Misoperation(s) reporting in Section C1.4 of the draft standard.**
5. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**
6. **The language in C 1.4 has been revised to refer to the Compliance Enforcement Authority.**
7. **The drafting team revised the definition of Misoperation as well as the Application Guidelines that discusses the new**

Organization	Yes or No	Question 9 Comment
definition. **8. Thank you for your comment.** **9. The drafting team revised the definition of Misoperation as well as the Guidelines and Technical Basis section that discusses the new definition.**		
Pacific Northwest Small Public Power Utility Comment Group		
LG&E and KU Energy		
APM Members		
PPL Generation		Requirement 1.5 states that the procedure shall include, "A requirement that the Registered Entity complete each CAP or action plan as outlined in its timetable, and document its completion as implemented." Schedule changes may be needed as a result of unforeseen events. This should be clarified to be "A requirement that the Registered Entity complete each CAP or action plan as outlined in its timetable or document the basis for needed schedule changes. The procedure shall also include a requirement to document its completion as implemented."
Response: Thank you for your comment. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**		
Florida Municipal Power Agency		see comments to Question 1
Bonneville Power Administration		BPA believes that the requirements in this standard to create and provide procedures and detailed descriptions of the processes used to analyze relay Misoperations are burdensome. In addition, BPA feels that the requirement to provide your own processes and procedures results in extra steps that waste valuable time. Documenting these processes and procedures and then providing them in self-certifications and at audits results in appreciable work. This step also results in one more potential audit violation.

Organization	Yes or No	Question 9 Comment
		This approach is the one that was used in PRC-005-1. There it resulted in inconsistent levels of relay maintenance between entities and inequitable penalties. That approach is being dropped in PRC-005-2, and BPA believes that it should not be used in this standard either. A more concise and acceptable standard would simply specify the minimum requirements for analyzing and documenting relay operations and not require the documentation of procedures and detailed descriptions of the processes used by individual entities.
Response: Thank you for your comment. **The details in the requirements are needed to ensure they are measureable and enforceable. The requirements have been revised to ensure only the necessary detail is included.**		
Western Area Power Administration	Yes	The SAR refers to WECC standards PRC-003-STD-1 and PRC-004-WECC-1. It talks about how those standards might overlap. It is our understanding that PRC-004-WECC-1 replaces PRC-003-STD-1 so we don't understand what NERC is getting at. Only one of those standards should be active at any point in time.
Response: Thank you for your comment. **The SAR is not referring to the two WECC standards overlapping each other, rather it is referring to those standards overlapping the proposed NERC Reliability Standard PRC-004-3.**		
Westar Energy		
Georgia Transmission Corporation	Yes	Will TADS be able to show the percentages of Misoperations versus total number of operations?
Response: Thank you for your comment. **This question is beyond the scope of this drafting team.**		
PacifiCorp		PacifiCorp suggests that Section 4.2.2 (regarding applicability of facilities) be revised to state as follows: "Special Protection Systems (SPS), Remedial Action Schemes (RAS), Under Frequency Load Shedding programs, and Under Voltage Load Shedding programs are excluded from this standard." PacifiCorp believes that the same rationale for excluding

Organization	Yes or No	Question 9 Comment
		UVLS programs from this proposed standard should apply for UFLS programs. If the Standards Drafting Team has a specific rationale for making UFLS programs subject to this standard, please provide an explanation as part of the revised standard circulated for the next formal comment and voting period. In accordance with the Standards Processes Manual, the drafting team will respond to comments made in response to the following question informally (in summary form only).
Response: Thank you for your comment. **Misoperation associated with SPS/RAS will be addressed in the second phase of this project: Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. The SAR for this project did not include modification of PRC-022-1 Under-Voltage Load Shedding Program Performance which covers Misoperations of UVLS. UFLS Misoperations are not covered by existing NERC standards.**		
NextEra Energy, Inc.	Yes	The CAPs and action plans are living documents that should be revised as additional information is gained. Requirement 1.3 should be revised to read (highlighted section added): o A Corrective Action Plan (CAP) (which may be amended as appropriate) that includes: Requirement 1.4 should be revised to read (highlighted section added): o An action plan (which may be amended as appropriate) that identifies:
Response: Thank you for your comment. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**		
Southern Company	Yes	Although we feel that tie back to TADS reporting will not accomplish the needed data unless TADS is modified to include 100-kV and above and generation facilities. Unless this is done, The tie back to TADS should be eliminated, if implemented, we would suggest the following modification: The recommendation is to state the actual range of TADS data collected. Proposed text - A review of the Transmission Availability Data System (TADS) data (20XX to 20XX) reveals that the fourth ranked initiating cause of BES outages not related to weather is “Failed Protection System Equipment.”
Response: Thank you for your comment. **Changes to TADS are beyond the scope of this drafting team.**		

Organization	Yes or No	Question 9 Comment
Flathead Electric Cooperative, Inc.		
Green Country Energy		
Hydro-Quebec TransÃ ‰ nergie	No	
Ingleside Cogeneration LP		
Oncor Electric Delivery	No	
Private Citizen	Yes	I thank the drafting team for their efforts to date and for the opportunity to comment. The job of a drafting team is not easy. My comments are as follows: 1) I just wanted to add what I thought the true Purpose of the standard is/should be: Misoperation analysis is a reactive tool - one waits for a Misoperation, then analyzes why it happened with the purpose of determining what, if any, changes need to be made to prevent another occurrence in the entity's system. Changes could be simple or complex, at one location or at many locations. Primarily, you are working to prevent a SECOND Misoperation. The SECOND misoperation could be either on existing system(s) or on future systems. I think it is important to note that it is the occurrence of the SECOND misoperation that is the true indicator of whether the efforts to prevent a Misoperation have been successful. A SECOND Misoperation indicates that it has not. 2) In R1, the drafting team calls for each entity to have a procedure. I am unclear on what benefit this provides, other than giving the auditors something to audit. Why not just call for an entity to do XYZ rather than say they must have a procedure that says they will do XYZ and they must follow the procedure. I see requiring a procedure as unnecessary documentation. Can the drafting team comment on why they asked for a procedure? 3) In R1.1, the drafting team calls for a "detailed" description. There is no measure for 'detailed". I believe the drafting team should seek to avoid such undefined terms. Shouldn't the standard just call for a procedure that includes the things listed in the

Organization	Yes or No	Question 9 Comment
		standard? Or better yet, not call for a procedure at all, but just say you must do XYZ? 4) In the Background, it states that one goal of the standard is to collect data to establish a metric to measure Protection System performance. While I think this is a worthy goal in theory, I am skeptical about its usefulness in practice. Protection systems are an Art, not a science, and while most protection systems are made from the same building blocks, the application of them can vary wildly from utility to utility. Before requiring data collection - which would presumably cause a utility to get a NERC violation for failing to send in the data - I would be curious to know how this has worked in the regions that do, today, collect this data. For instance, I believe SERC collects this kind of data. Has this proven useful for developing a metric for SERC entities? If it has not, why not? Let's not repeat a mistake on a continent wide basis. 5) CAPs - the drafting team has written all kinds of rules for CAPs, including trying to hold the entity to a work timetable. What if the entity chooses to say it will take 100 years to fix so that they avoid the possibility of getting a violation for missing their timetable? I personally think CAPs should be eliminated from the standard as they are simply un-workable. You cannot know whether the CAP makes sense without evaluating them on a case-by-case basis. Consider that the CAP actions fall into three broad areas: a) Do nothing (for any of a boat-load of reasons) b) Correct the issue at this one location c) Correct the issue at all locations Generally, c) is preferred, but there may be times when a) is the best solution, because fixing the issue may make things worse. So, instead, how about a performance standard, whereby an entity gets a violation if a Misoperation occurs a SECOND time. I'll be the first to admit that the devil is in the details, but at least in this case, we're getting at the true reason for the standard - preventing that SECOND occurrence. Ultimately, we don't care how they do it, as long as they do it.

Response: Thank you for your comments.

1. **Thank you for your comment.**
2. **Having a standardized process provides a consistent application for evaluating Protection System operations. The details in the requirements are needed to ensure they are measureable and enforceable. The requirements have been revised to ensure only the necessary detail is included.**

Organization	Yes or No	Question 9 Comment
3. The drafting team revised the standard and removed the word 'detailed'. **4. Consistently reported Misoperation data can be used to measure the reliability of BES Protection Systems over time.** **5. The SDT appreciates your observations. The SDT believes the establishment and completion of CAPs for Misoperations will be more effective in reducing future Misoperations than imposing violations for repeated Misoperations.**		
Consolidated Edison Co. of NY, Inc.	Yes	Although the inclusion of the Application Guideline is generally helpful, care is needed not to override the judgment of the Protection System owner for setting and designing its relay protection systems, particularly regarding the bias towards security or dependability. For example, the 4th paragraph on Page 14 ("Where studies have...) seems unduly prescriptive.
Response: Thank you for your comment. **The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. They are not mandatory or enforceable. The Protection System owner is responsible for the design of its protective systems.**		
Orange and Rockland Utilities, Inc.		None
PSE		
TransAlta		
Entergy Services		There are instances when an entity will justifiably need to defer a corrective action plan. The standard needs to include provisions to be able to adjust or defer corrective action plans if necessary.
Response: Thank you for your comment. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**		
GenOn Energy	Yes	The attempt to keep the Standard simple and straightforward is appreciated. 1. In the Requirements section, please simply state the intended requirement and

Organization	Yes or No	Question 9 Comment
		eliminate the repeated use of catch-all terms such as “any” and “all” which open the door to future unintended interpretations. 2. In R1.1, a “detailed” description is arbitrary and subjective. Reword the statement as follows: “A description of the processes used to:” 3. In R1.1.1, reword the requirement, “Identify and document Faults and Protection System operations.” Documenting “all BES Faults” covers the entire continent. 4. In Section R1.3 and R1.4, it is suggested to replace “a work timetable” with “a projected schedule.”
Response: Thank you for your comment **1. The SDT revised the draft standard.** **2. The SDT revised the draft standard and the word ‘detailed’ has been removed.** **3. The requirements have been rewritten. The "BES" reference was removed because BES is specified in the Applicability section 4.2.1. The "Faults" reference was removed because Misoperations may occur during non-fault conditions.** **4. The drafting team used the word ‘timetable’ to be consistent with the definition of a ‘Corrective Action Plan’ in the NERC Glossary of Terms.**		
Indiana Municipal Power Agency	Yes	1. A NERC Rapid Development Team (one industry stakeholder out of ten individuals) drafted the SAR and the first draft copy of PRC-004-3. IMPA believes SAR development in this manner is fine, but the first draft of a standard should not be written by the NERC Rapid Development Team. This new process should not compromise the current stakeholder process of writing reliability standards. By using the Rapid Development Team in the attempt to gain efficiency or speed, the risk of becoming inefficient and increasing drafting standard time is greater because problems will have to be address formally through comments and revisions instead of through the informal drafting work of the stakeholder’s standard drafting team. 2. IMPA appreciates the effort of trying to make the standard easier to understand by the use of Application Guidelines, but we are concern that the Application Guidelines will become, by association, part of the requirements of the standard. Application Guidelines will be used by auditors as a draft of what a Compliance Program should include and that registered entities will be required to comply with the suggestions

Organization	Yes or No	Question 9 Comment
		listed for Part 1.1 - Part 1.4 and Section C-1.4. For instance, it is stated that an investigation report generally includes the following information: 1) initial evidence, 2) probable or potential causes, 3) tests and studies, and 4) conclusions. Are utilities going to be required to have the supporting documentation required for each of these steps? For instance, as stated in the Application Guideline, initial evidence "...contains the sequence of events, relay targets, and a summary of Disturbance Monitoring Equipment (DME) records." However not all registered entities to which this draft Standard would apply to are currently required to have sequence of events and/or DME's. If this source of information is not available to them will they be penalized or forced to install this equipment thereby subjecting them to further Standards? In addition short circuit and coordination studies are mentioned as being included in report. These studies can be costly and time consuming - will utilities be required to provide these in a report for each operation in order to prove that it was not a "Misoperation"? Guidelines should be viewed as just that - a guideline and should not be viewed as what a utility should include in their Compliance Program. For this standard, it has about a page and a quarter of requirements and almost five pages of Application Guidelines to tell an entity how to be in compliant. The requirements should be written in a manner to stand by themselves without guidelines and allow an entity the option of determining the best method of being in compliance with the requirement.
Response: Thank you for your comments. **1. The drafting team forwarded your comment to the NERC Standards Committee and NERC staff.** **2. The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the standard is not mandatory or enforceable.**		
Exelon	Yes	What are the reporting expectations when a Protection System misoperation occurs between entities and the failure is with the one of the entities? Would the entity not responsible for the cause also report a misoperation as a means to show cooperation?
Response: Thank you for your comments. **The owner of the Protection System component that misoperated is required to report the misoperation.**		

Organization	Yes or No	Question 9 Comment
Manitoba Hydro		
Tacoma Power		The word 'detailed' should be removed from R1.1. Under R1.3, replace 'Interim corrective actions' with 'Interim corrective or mitigating actions.'
Response: Thank you for your comment. **The SDT revised the draft standard and the word 'detailed' has been removed.**		
Ameren		1) The industry is in the process of adopting the RAPA template. We disagree with the Background statement that Misoperation data, as currently collected and reported is not usable. It seems to us that plenty of Misoperation statistics have been issued, though they may be misleading. 2) We have been through multiple audits and regional reviews of our reported Misoperations, and strongly disagree with the Background statement that the present PRC003 / 4 status is a 'reliability gap'. 3) Are the "Guidelines and Technical Basis" part of the standard? What is their purpose? They do provide a reasonable engineering practice explanation in several cases. In item (3), please strike "or by coordination requirements with other Protection Systems." 4) The evidentiary requirements of this proposed standard greatly exceed those of the present standard, and rigid timelines are required. Entities need more time to make software changes, increase and train staff, and implement processes. Please change implementation to 'first day... 6 months after applicable regulatory approval'. 5) The standard and implementation plan should also exclude UFLS. Add 'Underfrequency Load Shedding' in 4.2.2.
Response: Thank you for your comment. **1. Thank you for your comment.** **2. Thank you for your comment.** **3. The Guidelines and Technical Basis section of the standard is there to provide further explanation and the thought processes of the drafting team as they developed the requirements. The Guidelines and Technical Basis section of the**		

Organization	Yes or No	Question 9 Comment
standard is not mandatory or enforceable. **4. The drafting team agreed and changed the effective date to twelve months after applicable regulatory approval.** **5. UFLS Misoperations are not covered by existing NERC standards.**		
Utility Services, Inc.		While we understand the need to move the Standards Development process on a faster pace, aka Rapid Development process; Utility Services feels that the RD p should not have the initial standard language drafted by RD p group. The SDT should be the group to draft the initial requirements. As outlined in the ROP, industry should be leading this effort.
Response: Thank you for your comments. **The drafting team forwarded your comment to the NERC Standards Committee and NERC staff.**		
American Electric Power		1. Why is it necessary to have PRC-004 along with both PRC-006 and PRC-016? It is not clear why these cannot also be addressed in this revision process, as for AEP, it would seem to be a natural extension of these responsibilities. 2. We suggest there should there be an explicit requirement regarding reporting, rather than providing this detail within the Compliance section. 3. It is not clear how much flexibility, if any, there is in completing investigative work in a timetable as required by R 1.5. For example, due to outages or required maintenance activities, one might not be able to meet the date as set within the timetable, which would require a new proposed completion date. If one were to be held to the standard "literally", is it even allowable to complete the work early? Though the application guide seems to partially address allowing changes to the CAP, the standard should be more explicit in doing so.
Response: Thank you for your comments. 1. **Misoperation associated with SPS/RAS will be addressed in the second phase of this project: Project 2010-05.2 Phase 2 of Protection Systems: SPS and RAS. The SAR for this project did not include modification of PRC-022-1 Under-Voltage Load Shedding Program Performance which covers Misoperations of UVLS. UFLS Misoperations are not covered by any existing NERC standards.** 2. **The drafting team explored various avenues for Misoperation(s) reporting such as including it as a standard requirement or as a Section 1600 data request, but did not believe either was appropriate. NERC staff has encouraged**		

Organization	Yes or No	Question 9 Comment
drafting teams to remove administrative and reporting requirements from the body of standards. These types of requirements do not have direct impact on reliability. The SDT included periodic data submittals in Section C 1.3 "Compliance Monitoring and Assessment Processes" of the standard and included a description identifying what to submit and the periodicity for submittal to the Compliance Enforcement Authority in Section C 1.4 "Additional Compliance Information". 3. **The drafting team revised the draft standard and the new Requirement R4 allows for revisions to CAPs.**		
American Transmission Company, LLC		
CenterPoint Energy		CenterPoint Energy recommends that Under Frequency Load Shedding programs be excluded from this standard. In the Applicability section of PRC-004-3, 4.2.2 should be written as follows: "Special Protection Systems (SPS), Remedial Action Schemes (RAS), Under Frequency Load Shedding programs (UFLS), and Under Voltage Load Shedding programs (UVLS) are excluded from this standard."
Response: Thank you for your comment. **UFLS Misoperations are not covered by any existing NERC standards.**		
BGE	No	No comment.
Consumers Energy	Yes	1) The reporting template describes several types of events that are "not reportable Misoperations". These types of events should also be specifically excluded in the standard, especially operations that occur during on-site activities. 2) The Effective Dates, listed in the Implementation Plan, are confusing as written. We suggest "first day of the first calendar quarter, at least 3 months after..." 3) Section 4.2.1 of the Applicability indicates the Standard is applicable to "Protection Systems". Since Protection System is capitalized, this indicates it is defined in the NERC Glossary. Is the intent of this standard to be inclusive of all protection system components (relays, cts, vt, dc circuits, and station batteries)? 4) In M2 remove "written lists". We are suggesting that no reference be made to lists.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. **1. The SDT has modified the definition of Misoperation to address on-site activities."** **2. Thank you for your suggestion. The drafting team changed the effective date to twelve months after applicable regulatory approval.** **3. Yes.** **4. The measures provide examples of acceptable evidence that can be used to demonstrate compliance with the requirements. Lists are one of the acceptable forms of evidence.**		
ITC		Based on the specified time intervals quarterly reports will likely hinder the process, suggest changing the data submittal to semiannual and for it to be submitted within 90 days following the end of the first or second half of the year.
Response: Thank you for your comment. **The drafting team retained the quarterly reporting period for Protection System Misoperation(s).**		
Wisconsin Electric		
Duke Energy	Yes	1. We like having the "Guidelines and Technical Basis" as part of the standard. For clarity, revise the third paragraph under Section 5 of the "Guidelines and Technical Basis" as follows: Failure to automatically reclose after a fault is not included as a Protection System Misoperation because reclosing equipment is not included under the definition of Protection Systems. Further, operations which are initiated by control systems (not by Protection Systems), such as those associated with generator and excitation controls, protection used during generator startup and shutdown (such as reverse power relaying), or turbine/boiler controls, Static VAR Compensators (SVCs), Flexible AC Transmission Systems (FACTS), High-Voltage DC (HVDC) transmission systems, circuit breaker mechanisms, or other facility control systems are also not Misoperations of a Protection System. 2. The requirements to have documented processes for identifying, analyzing and reporting Misoperations as well as CAP and action plan tracking may impact some entities. For such entities, the Implementation Plan may not allow sufficient time to both develop and implement additional processes.

Organization	Yes or No	Question 9 Comment
Response: Thank you for your comments. **1. The SDT revised the Guidelines and Technical Basis section to include more explanation.** **2. The drafting team agreed and changed the effective date to 12 months after applicable regulatory approval.**		
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board		
BC Hydro	Yes	BC Hydro requests clarification for underfrequency load shedding schemes (UVLS). Would they fall under this standard?
Response: Thank you for your comment. **The SAR for this project did not include modification of PRC-022-1 Under-Voltage Load Shedding Program Performance which covers Misoperations of UVLS. UFLS Misoperations are not covered by any existing NERC standards.**		

10. In accordance with the Standards Processes Manual, the drafting team will respond to comments made in response to the following question informally (in summary form only).

If you have any comments on the draft SAR, please provide them here.

Summary Consideration:

A commenter had a concern with reviewing each Protection System operation. The SDT believes that an entity must look at (review) every Protection System operation to determine if a Misoperation has occurred. The standard does not attempt to define a review so as to leave the method of conduct of the review up to the entity. Measure M1 has been modified and provides examples of acceptable evidence to satisfy the review of operations Requirement. The SDT believes the review of Protection System operations is being performed already and just needs to be formally documented.

A commenter stated they believe that having a Misoperation makes them non-compliant. A Misoperation is not a violation of PRC-004 regardless of the cause. The purpose of PRC-004 is to identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.

A request was made to add Protection System operation review to the Title and Purpose of the standard. The SDT disagrees because the focus is Misoperation identification and mitigation.

One commenter wanted to be exempt from this standard because they are a nuclear generator operator and fall under NRC rules. The NRC requirements cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC.

Organization	Yes or No	Question 10 Comment
Northeast Power Coordinating Council		
Public Service Enterprise		

Organization	Yes or No	Question 10 Comment
Group Company		
Hydro One		
Tri-State Generation and Transmission Ass'n - System Protection		None
FirstEnergy		
Pepco Holdings Inc Affiliates		
Southern Company Generation		
Transmission Access Policy Study Group		
SPP Reliability Standards Development Team		
MRO's NERC Standards Review Forum		
Electric Market Policy		See response to Question 6 above.
Pacific Northwest Small Public Power Utility Comment Group		
LG&E and KU Energy		
APM Members		
PPL Generation		

Organization	Yes or No	Question 10 Comment
Florida Municipal Power Agency		1) A concerning statement in the SAR is the proposal to add a requirement to the standard to: "Review all Faults or Protection System operations on the BES to identify those that are BES Protection System Misoperations". We are uncomfortable with the word "review". We would imagine only those protection system operation that fell outside of a certain tolerance would need to be reviewed, e.g., more than one Element tripped, the trip took longer than X cycles, a trip happened without a fault, etc. Review implies something more than looking to see if a criteria was met for further review. So, does review mean to evaluate whether certain criteria was met, or to do a thorough review? We're concerned with the administrative burden of having to do more than a high level review for each and every protection system operation or fault. 2) What sort of evidence would be required to prove that we looked at every Protection System operation and fault on the BES? 3) This could create an unnecessary administrative burden on the industry. 4) Also, in the white paper, the paper identifies incorrect settings as a misoperation (see Table 2 on Cause Codes). To us, incorrect setting is not a misoperation and to call it such creates double jeopardy. If an engineer calculates the incorrect setting for a relay, that should be a PRC-001 standard implication. If a relay tech puts the wrong setting in the relay and tests to that wrong setting that should be a PRC-005 issue, and not a PRC-004 issue.
Response: Thank you for your comments. **1) The Standard Drafting Team believes that an entity must look at (review) every Protection System operation to determine if a Misoperation has occurred. The standard does not attempt to define a review so as to leave the method of conduct of the review up to the entity. Your method of review seems acceptable but compliance review is up to each Regional Entity.** **2) Measure M1 has been modified and provides examples of acceptable evidence to satisfy Requirement R1.** **3) The SDT believes this review is being performed already and just needs to be formally documented.** **4) The SDT disagrees. A Misoperation is not a violation of PRC-004-3 regardless of the cause. The purpose of PRC-004-3 is to identify and correct the causes of Misoperations of Bulk Electric System (BES) Protection Systems.**		
Bonneville Power Administration		

Organization	Yes or No	Question 10 Comment
Western Area Power Administration		
Westar Energy		
Georgia Transmission Corporation		
PacifiCorp		No comments.
NextEra Energy, Inc.		
Southern Company		
Flathead Electric Cooperative, Inc.		
Green Country Energy		
Hydro-Quebec TransÃ ‰ nergie		No comment
Ingleside Cogeneration LP		
Oncor Electric Delivery		
Private Citizen		I'm not in the industry anymore, but I think the SAR assumes things that are not truly agreed upon by the industry. My comments are as follows: 1) Review all BES faults/operations - see my comments in Q9. 2) I do not believe the industry is in agreement that all operations need to be reviewed. Presumably, one could review a sub-set and capture the vast majority of potential Misoperations. This would be a better use of resources. So, my complaint here is that the SAR should not tie the hands of the drafting team by requiring that all operations are

Organization	Yes or No	Question 10 Comment
		reviewed unless it makes sense. 3) CAPs - again, see my comments in Q9. I'm unconvinced that you need lots of rules for CAPs. I think a performance requirement would be a better way to go. My complaint here is that it is too prescriptive. Again, the hands of the drafting team should not be tied like this.
Response: Thank you for your comments. **1) See the SDT response to your comment in Q9.** **2) The Standard Drafting Team believes that an entity must look at (review) every Protection System operation to determine if a Misoperation has occurred. The standard does not attempt to define a review so as to leave the method of conduct of the review up to the entity. Review of a subset of all operations, while probabilistically significant, would not serve reliability properly. The SDT believes this review is being performed already and just needs to be formally documented.** **3) See the SDT response to your comment in Q9. If a Misoperation occurs, it needs to be corrected and documented in a Corrective Action Plan. The SDT believes the SAR is not too prescriptive regarding Corrective Action Plans.**		
Consolidated Edison Co. of NY, Inc.		
Orange and Rockland Utilities, Inc.		None
PSE		Combining similar standards and clarifying definitions or requirements is always good. Thanks for the effort.
Response: Thank you for your comment.		
TransAlta		1) The Standard title would be: Protection System Operation Analysis and Protection System Misoperation Identification and Correction 2) The Purpose of this standard would be: Analyze the causes of operation of BES Protection systems and identify and correct the causes of Misoperation of BES Protection Systems.

Organization	Yes or No	Question 10 Comment
Response: Thank you for your comments. **1. The SDT believes the title is adequate.** **2. The SDT believes the purpose correctly defines the reliability goal of the standard.**		
Entergy Services		
GenOn Energy		
Indiana Municipal Power Agency		no comments
Exelon		Exelon Nuclear: Nuclear GO/GOPs have an existing Corrective Action Program that is required by 10 CFR 50 Appendix B Criterion XVI (quoted below). This regulatory requirement and associated mandatory implementation of a Corrective Action Program by a Nuclear GO/GOP fully envelopes the intent of the draft revision to PRC-004. An additional "procedure" to identify and address all Protection System Misoperations with set timelines and attributes is not necessary."XVI. Corrective Action Measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The identification of the significant condition adverse to quality, the cause of the condition, and the corrective action taken shall be documented and reported to appropriate levels of management."
Response: Thank you for your comments. **These requirements cannot be used as a substitute for PRC-004-3 since they do not apply to Protection Systems on the electrical side of nuclear plants. In Order 706-B, FERC stated that much of a nuclear plant does not fall under the rules of the NRC. The NRC rules are applicable to the portions of the nuclear plant related to handling of radiological fuel, security and safety. NERC rules apply to the portion of the plant not under the rules of the NRC. BES electrical Protection Systems do not fall under the rules of the NRC.**		
Manitoba Hydro		

Organization	Yes or No	Question 10 Comment
Tacoma Power		None
Ameren		
Utility Services, Inc.		
American Electric Power		
American Transmission Company, LLC		
CenterPoint Energy		
BGE		No comment.
Consumers Energy		
ITC		1) Suggest changing the first bullet to begin "Review all Faults or outages caused by Protection System operations...". 2) The draft standard 4.2.2 indicates that SPS, RAS and UVLS programs are excluded and this should also be indicated in the SAR.
Response: Thank you for your comments. **1) The SDT removed BES Faults from the requirements because review of all Protection System operations would include Faults and some operations/Misoperations do not involve Faults. All Protection System operations should be reviewed because their cause could be a fault, or the outage could be caused by a Protection System Misoperation.** **2) The SDT disagrees. The SAR is larger in scope while the Applicability section of the standard sets limits.**		
Wisconsin Electric		
Duke Energy		

Organization	Yes or No	Question 10 Comment
Constellation Power Generation/Constellation Energy Nuclear Group		
Springfield Utility Board		
BC Hydro		

END OF REPORT