NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Protection System Maintenance and Testing – Project 2007-17

The Protection System Maintenance and Testing Drafting Team would like to thank all commenters who submitted comments on the first draft of the PRC-005-2 standard for Protection System Maintenance and Testing (Project 2007-17). This standard and its associated documents were posted for a 45-day public comment period from August 15, 2011 through September 29, 2011. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 48 sets of comments, including comments from approximately 147 different people and approximately 98 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.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 and Director 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:

SAR:

The SDT made several changes to the SAR. The proposed title of the standard was changed to 'Protection System Maintenance'; Reliability Principle item #4 was removed as it does not apply to the standard; and the 'Transmission and Generation' descriptor of Protection Systems was removed from the Detailed Description area of the SAR.

Applicability:

The SDT revised Applicability 4.2.5.4 to indicate that, for generator-connected station service transformers, only the Protection Systems that trip the generator, either directly or via a lockout relay, are included in the standard.

Requirements:

Requirement R1 part 1.3 has been removed.

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

The SDT split Requirement R3 into three separate requirements for better clarity.

Requirement R3 has been revised so that, for time-based programs, entities must comply with the standard's tables rather than their PSMP. Requirement R3 now reads:

> **R3.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes time-based maintenance program(s) shall maintain its Protection System components that are included within the time-based maintenance program in accordance with the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3.

Requirement R4 has been added to address performance-based maintenance. The new Requirement R4 is as follows:

> **R4.** Each Transmission Owner, Generator Owner, and Distribution Provider that utilizes performance-based maintenance program(s) in accordance with Requirement R2 shall implement and follow its PSMP for its Protection System components that are included within the performance-based program.

Requirement R5 has been added to address Unresolved Maintenance Issues. The definition of the term 'Unresolved Maintenance Issues' has been enhanced for additional clarity, and now reads:

> ***Unresolved Maintenance Issue*** *- A deficiency identified during a maintenance activity that causes the component to not meet the intended performance and requires follow-up corrective action.*

The new Requirement R5 is as follows:

> **R5**. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues.

Measures

The SDT revised and drafted new measures to comport with the requirements.

Tables

Most commenters seemed to agree in general that the restructured Tables added clarity and some commenters offered suggestions for further improvement. Minor clarifying changes were made to the Tables themselves, and additional discussion was added to the "Supplementary Reference and FAQ" document to address various comments.

In Table 1-5 (Component Type - Control Circuitry Associated With Protective Functions), the SDT removed the auxiliary relays from the 6 year periodic maintenance associated with electromechanical lockout devices, and included them in the 12 year periodic maintenance associated with the unmonitored control circuitry associated with protective functions.

Table 1-4(f) was modified to more accurately represent the monitoring attributes and related activities for monitored Vented Lead-Acid and Valve-Regulated Lead-Acid batteries.

Implementation Plan

Minor clarifying changes were made to the Implementation Plan.

VLSs:

Changes were made to the make the VSLs conform to the new and changed requirements.

Supplementary Reference Document

Changes were made to the "Supplementary Reference and FAQ" document, corresponding to all changes to the standard.

Unresolved Minority Views:

- A few commenters continued to object to the establishment of maximum allowable intervals for the maintenance of various Protection System component types. The SDT continued to respond that FERC Order 693 and the approved SAR direct the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The SDT believes that the intervals established within the Tables are appropriate as continent-wide maximum allowable intervals.

- Several commenters were concerned that an entity has to be "perfect" in order to be compliant; the SDT responded that NERC Standards currently allow no provision for any degree of non-performance relative to the requirements.

- Several commenters continued to insist that "grace periods" should be allowed. The SDT continued to respond that grace periods would not be measurable.

- Several commenters continued to question the propriety of including distribution system Protection Systems, almost all related to UFLS/UVLS. The SDT obtained a position from NERC legal staff, and cited this position in responding that these devices are indeed within NERC's authority because they are installed for the reliability of the BES.

- A few commenters questioned the inclusion of the direct current (dc) control circuitry for sudden pressure relays even though the relays themselves are excluded from the definition of "Protection System"; the SDT reiterated its position that this dc control circuitry is included because the dc control circuitry is associated with protective functions.

- A few commenters objected to the language in the Data Retention section regarding the retention of the maintenance records for two full intervals. The SDT explained that this expectation is consistent with the Compliance Monitoring and Enforcement Program.

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.	Michael Schiavone	National Grid	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Kathleen Goodman	ISO - New England	NPCC	2
10.	Chantel Haswell	FPL Group, Inc.	NPCC	5

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

11. David Kiguel	Hydro One Networks Inc.	NPCC	1
12. Michael Lombardi	Northeast Utilities	NPCC	1
13. Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14. Bruce Metruck	New York Power Authority	NPCC	6
15. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16. Robert Pellegrini	The United Illuminating Company	NPCC	1
17. Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18. David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
19. Saurabh Saksena	National Grid	NPCC	1
20. Wayne Sipperly	New York Power Authority	NPCC	5
21. Donald Weaver	New Brunswick System Operator	NPCC	2
22. Ben Wu	Orange and Rockland Utilities	NPCC	1

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

Additional Member	Additional Organization	Region	Segment Selection
1. Rusty Harison	TOM Support	SERC	1
2. Pat Caldwell	TOM Support	SERC	1
3. Paul Barnett	Tom Support	SERC	1
4. David Thompson	TVA Compliance	SERC	5
5. Jerry Finley	Power Control Systems	SERC	1
6. Frank Cuzzort	TVA Generation - Nuclear	SERC	5
7. Robert Brown	TVA Generation - Nuclear	SERC	5
8. Roberts Mares	TVA Generation - Fossil	SERC	5
9. Annette Dudley	TVA Generation - Hydro	SERC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Ron Sporseen	PNGC Comment Group	X		X	X				X		

Additional Member	Additional Organization	Region	Segment Selection
1. Bud Tracy	Blachly-Lane Electric Cooperative	WECC	3
2. Dave Markham	Central Electric Cooperative	WECC	3
3. Dave Hagen	Clearwater Power	WECC	3
4. Roman Gillen	Consumer's Power	WECC	1, 3
5. Roger Meader	Coos-Curry Electric Cooperative	WECC	3
6. Dave Sabala	Douglas Electric Cooperative	WECC	3

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

7. Bryan Case	Fall River Electric Cooperative	WECC	3
8. Rick Crinklaw	Lane Electric Cooperative	WECC	3
9. Michael Henry	Lincoln Electric Cooperative	WECC	3
10. Richard Reynolds	Lost River	WECC	3
11. Jon Shelby	Northern Lights	WECC	3
12. Ray Ellis	Okanogan Electric Cooperative	WECC	3
13. Aleka Scott	PNGC Power	WECC	4
14. Heber Carpenter	Raft River Electric Cooperative	WECC	3
15. Ken Dizes	Salmon River Electric Cooperative	WECC	1, 3
16. Steve Eldrige	Umatilla Electric Cooperative	WECC	3, 1
17. Marc Farmer	West Oregon Electric Cooperative	WECC	3
18. Margaret Ryan	PNGC Power	WECC	8
19. Stuart Sloan	Consumer's Power	WECC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Chris Higgins	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dean Bender	SPC Technical Svcs	WECC	1
2. John Kerr	Technical Operations	WECC	1
3. Lorissa Jones	Transmission Internal Ops	WECC	1
4. Greg Vassallo	Customer Service Engineering	WECC	1
5. Mason Bibles	Sub Maint and HV Engineering	WECC	1
6. Deanna Phillips	FERC Compliance	WECC	1, 3, 5

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

Additional Member	Additional Organization	Region	Segment Selection
1. Michael Crowley	Virginia Electric and Power Company	SERC	1, 3
2. Michael Gildea	Dominion Resources Services, Inc.	MRO	5
3. Louis Slade	Dominion Resources Services, Inc.	RFC	5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Kinney	FE	RFC	1
2. Craig Boyle	FE	RFC	1
3. Frank Hartley	FE	RFC	1

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

4. Bill Duge	FE	RFC	5
5. Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7. Group	Robert Rhodes	Southwest Power Pool Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. John Allen	City Utilities of Springfield, Missouri	SPP	1, 4
2. Forrest Brock	Western Farmers Electric Cooperative	SPP	1, 3, 5
3. Anthony Cassmeyer	Western Farmers Electric Cooperative	SPP	1, 3, 5
4. Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
5. Louis Guidry	CLECO Power	SPP	1, 3, 5
6. Jonathan Hayes	Southwest Power Pool	SPP	2
7. Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
8. Ashley Stringer	Oklahoma Municipal Power Authority	SPP	4

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

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Mallory Huggins	NERC Staff Technical Review										

No additional members listed.

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	David Thorne	Pepco Holdings Inc & Affiliates	X		X							

Additional Member	Additional Organization	Region	Segment Selection
1. Carlton Bradshaw	Delmarva Power and Light	RFC	1

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

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

	Additional Member	Additional Organization	Region	Segment Selection
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

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	James Jones	AEPCO/SWTC	WECC	1, 3, 5
2.	Lindsay Shepard	Sunflower Electric Power Corporation	SPP	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Individual	Janet Smith, Regulaory Compliance Supervisor	Arizona Public Service Company	X		X		X	X				
14.	Individual	Bill Shultz	Southern Company Generation					X				X	
15.	Individual	Bo Jones	Westar Energy	X		X		X	X				
16.	Individual	Max Emrick	Tacoma Power	X		X	X	X	X				
17.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
18.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
19.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
20.	Individual	Mary Jo Cooper	ZGlobal Engineering and Energy Solutions								X		
21.	Individual	Nicholas R. Finney	Saft America, Inc.								X		
22.	Individual	Tony Eddleman	Nebraska Public Power District	X		X		X				X	

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	John Bee	Exelon	X		X		X					
24.	Individual	Don Jones	Texas Reliability Entity										X
25.	Individual	Steve Alexanderson	Central Lincoln			X	X					X	
26.	Individual	Dan Roethemeyer	Dynegy Inc.					X					
27.	Individual	Thad Ness	American Electric Power	X		X		X	X				
28.	Individual	Eric Ruskamp	Lincoln Electric System	X		X		X	X				
29.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
30.	Individual	Edward Davis	Entergy Services	X		X		X	X				
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
33.	Individual	Kirit Shah	Ameren	X		X		X	X				
34.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
35.	Individual	Gary Kruempel	MidAmerican Energy Company	X		X		X					
36.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
37.	Individual	Andrew Z. Pusztai	American Transmission Company	X									
38.	Individual	Antonio Grayson	Southern Company Transmission	X		X		X					
39.	Individual	Brian Evans-Mongeon	Utility Services, Inc								X		
40.	Individual	Michael Moltane	ITC Holdings	X									
41.	Individual	Michelle D'Antuono	Igleside Cogeneration LP					X					
42.	Individual	Armin Klusman	CenterPoint Energy	X									
43.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									
44.	Individual	Tracy Richardson	Springfield Utility Board			X							
45.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
46.	Individual	Gerry Schmitt	BGE	X									
47.	Individual	Amir Hammad	Constellation Power Generation					X					
48.	Individual	Brenda Powell	Constellation Energy Commodities Group						X				

1. **Do you have any comments regarding the existing SAR for this project?**

Summary Consideration: In response to the comments, the SDT made several changes to the SAR.

1. The proposed title of the standard was changed to 'Protection System Maintenance.'

2 Reliability Principle item #4 was removed as it does not apply to the standard.

3 The 'Transmission and Generation' descriptor of Protection Systems was removed from the Detailed Description area of the SAR.

Several comments were offered, suggesting that the SAR address validating the accuracy of settings calculations provided to the field test personnel. The SDT declined to modify the SAR because they believe validating the accuracy of settings as provided to testing personnel is an internal management issue that should be addressed by the entity, and is beyond the scope of a 'maintenance and testing' standard.

Several comments were offered, suggesting that "the requirements should reflect the inherent differences between various protection system technologies," however the requirements should not mandate different testing methods and testing intervals based on that technology." The SDT declined to modify the SAR because they believe the current PRC-005-2 draft does not mandate specific testing methods; the responsible entity has latitude in establishing its PSMP. Specific activities (such as those for various technologies of "station dc supply") are prescribed, but the entity still has discretion in determining the most appropriate method of conducting those activities.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	Yes	Maintenance and testing of protection systems is the final step in the process that begins with the calculation of settings. The calculation of settings is followed by the application of those settings to the equipment. Maintenance and testing ensures that the settings given to testing personnel have been applied as given. This Standard addresses the Maintenance and Testing of protection systems. It should also address the need to validate the accuracy of the settings given to the field. A statement should be added to the SAR to address this need.
Response: Thank you for your comment. You are correct in your observation that the standard, as established in the project scope, addresses the maintenance and testing of Protection Systems. The SDT believes validating the accuracy of settings as		

Organization	Yes or No	Question 1 Comment
provided to testing personnel is an internal management issue that should be addressed by the entity, and is beyond the scope of a 'maintenance and testing' standard. Thus, the SDT does not believe that the SAR should be modified.		
ZGlobal Engineering and Energy Solutions	Yes	Table 1-4(a-c) excludes distributed UFLS and UVLS for batteries but references Table 3. Table 3 does not mention an interval for batteries. Is this an error?
Response: Thank you for your comment. In Table 3 we address the dc supply for tripping only non-BES interrupting devices as part of the UFLS and UVLS system. Table 3 explicitly limits the activities and intervals for station dc supply (relative to distributed UVLS/UFLS) to verifying the Protection System dc supply voltage every 12 calendar years, and requires nothing beyond that for station batteries in this application. This is not an error within the standard.		
Utility Services, Inc	Yes	We would urge that the SAR be modified to include Validation of Protection System settings. Presently, the standard does not provide for the explicit validation of the settings and it is possible that such mis-settings could be the reason for a misoperation. If a validation of the settings was explicitly called for in the standard, then the misoperation would be less likely to occur for that reason.
Response: Thank you for your comment. The SDT believes validating the accuracy of settings as provided to testing personnel is an internal management issue that should be addressed by the entity, and is beyond the scope of a 'maintenance and testing' standard. Thus, the SDT does not believe that the SAR should be modified. If this becomes a "Misoperation" problem for the entity, NERC Reliability Standard PRC-004-2 requires the entity to develop and implement a Corrective Action Plan to address the cause of the Misoperation.		
Constellation Power Generation	Yes	Although Constellation Power Generation agrees with some of the refinements prescribed in the SAR, there are a few items of concern. Constellation Power Generation agrees that "the requirements should reflect the inherent differences between various protection system technologies," however the requirements should not mandate different testing methods and testing intervals based on that technology. The Registered Entity should be given the latitude to address different technologies through its PSMP, and the requirements should reflect that.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comment. The SDT believes the current PRC-005-2 draft does not mandate specific testing methods; the responsible entity has latitude in establishing its PSMP. Specific activities (such as those for various technologies of “station dc supply”) are prescribed, but the entity still has discretion in determining the most appropriate method of conducting those activities.		
Constellation Energy Commodities Group	Yes	Although Constellation Energy Commodities Group agrees with some of the refinements prescribed in the SAR, there are a few items of concern. Constellation Energy Commodities Group agrees that “the requirements should reflect the inherent differences between various protection system technologies,” however the requirements should not mandate different testing methods and testing intervals based on that technology. The Registered Entity should be given the latitude to address different technologies through its PSMP, and the requirements should reflect that.
Response: Thank you for your comment. The SDT believes the current PRC-005-2 draft does not mandate specific testing methods; the responsible entity has latitude in establishing its PSMP. Specific activities (such as those for various technologies of “station dc supply”) are prescribed, but the entity still has discretion in determining the most appropriate method of conducting those activities.		
Saft America, Inc.	Yes	
Manitoba Hydro	No	**1.** Detailed Description: The phrase “Transmission & Generation Protection Systems” used in paragraph 1 should be “Transmission and generation Protection Systems”. “Transmission” and “Protection System” are defined words in the NERC Glossary of Terms; “Generation” is not a defined term and should not be capitalized. **2.** Applicable Reliability Principles: Is item 4 [Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.] applicable to Protection System Maintenance?
Response: Thank you for your comment.		

Organization	Yes or No	Question 1 Comment
1. **The SAR has been modified in consideration of your comment. The SDT removed the "Transmission & Generation" descriptors from the sentence.** 2. **The SAR has been modified in consideration of your comment. The Applicable Reliability Principle 4 has been unchecked as it is not applicable to this standard.**		
Tennessee Valley Authority	No	
PNGC Comment Group	No	
Bonneville Power Administration	No	
Dominion	No	
FirstEnergy	No	
Southwest Power Pool Standards Review Group	No	
Florida Municipal Power Agency	No	
NERC Staff	No	

Organization	Yes or No	Question 1 Comment
Technical Review		
Pepco Holdings Inc & Affiliates	No	
MRO's NERC Standards Review Forum	No	
ACES Power Collaborators	No	
Arizona Public Service Company	No	
Southern Company Generation	No	
Westar Energy	No	
Tacoma Power	No	
Progress Energy	No	
Western Area Power Administration	No	

Organization	Yes or No	Question 1 Comment
PacifiCorp	No	
Nebraska Public Power District	No	
Exelon	No	
Texas Reliability Entity	No	
Central Lincoln	No	
Dynegy Inc.	No	
Lincoln Electric System	No	
NIPSCO	No	
Entergy Services	No	
Independent Electricity System Operator	No	
Liberty Electric Power LLC	No	

Organization	Yes or No	Question 1 Comment
Ameren	No	
Northeast Utilities	No	
MidAmerican Energy Company	No	
American Transmission Company	No	
Southern Company Transmission	No	
ITC Holdings	No	
Igleside Cogeneration LP	No	
Oncor Electric Delivery Company LLC	No	
Springfield Utility Board	No	
City of Austin	No	

Organization	Yes or No	Question 1 Comment
dba Austin Energy		
BGE	No	No comment.
Response: Thank you for your comment.		

2. In response to comments, the term "Maintenance Correctable Issue" was revised to "Unresolved Maintenance Issue". Do you agree with this change? If you do not agree, please provide specific suggestions for improvement.

Summary Consideration: Most commenters agreed with the change in the term from "Maintenance Correctable Issue" to "Unresolved Maintenance Issue", with some offering further suggestion for improvement and clarification. Several commenters expressed concern that, without further clarity, auditors may confuse <u>initiation</u> of resolution for an issue with <u>completion</u> of the activities necessary to ultimately resolve the issue, but the SDT believes that this term (and its use within the Standard) is unequivocal. In response to comments, the SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 (shown below) and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues. Demonstrating the entity has initiated resolution can include such things as documentation of a work order, replacement component order, invoice, or purchase order, etc… Producing evidence of this nature would then indicate adherence to the requirement.

Requirement R5 now reads:

R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate efforts to correct identified Unresolved Maintenance Issues.

Organization	Yes or No	Question 2 Comment
Occidental Chemical	Affirmative Ballot	In response to comments, the term "Maintenance Correctable Issue" was revised to "Unresolved Maintenance Issue". Do you agree with this change? If you do not agree, please provide specific suggestions for improvement. Yes. The original term inferred that the problem detected was correctible through follow-up maintenance – which is not always the case. The term "Unresolved Maintenance Issue" is more appropriate.
Response: Thank you for your comment and your Affirmative Ballot.		
Independent Electricity System	Yes	The IESO agrees with the revision to the term. However, we observed the inconsistent format of this defined term used throughout the draft standard and would like to point it out to the Drafting Team. The capitalized term "Unresolved Maintenance Issue" is defined on Page 2 and used as a capitalized term in the blue box on Page 5. The defined term was made

Organization	Yes or No	Question 2 Comment
Operator		lowercase and used in other areas of the document as "unresolved maintenance issues" (eg. Page 5 and Page 8). We recommend that the format of this defined term be consistent throughout the draft standard.
Response: Thank you for your comment. The SDT has capitalized the term throughout the standard for consistency.		
MidAmerican Energy Company	Yes	1. Requirement R3 includes the following: "and initiate resolution of any unresolved maintenance issues". For clarification it is recommended that the following change be made to this phrase: "initiate resolution of any unresolved Protection System maintenance issues". 2. Also it is recommended that the following be added to the list in M3: "work management system information".
Response: Thank you for your comment. **1. The SDT observes that your concern is addressed by the Applicability of the standard (specifically addressing Protection Systems), and that the change you suggest is unnecessary.** **2. The language of Measure M3 specifies "*may include but is not limited to dated maintenance records …*" and could include records and information from a work management system without excluding other maintenance records an entity might have outside a work management system.**		
Utility Services, Inc	Yes	While this helps, we are concerned that during the term of the Unresolved Maintenance Issue is being resolved, a question of compliance to the standard might be pending out. It should be clarified that during this term, compliance to the standard is being satisfied and not deemed to be non-compliant.
Response: Thank you for your comment. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues.		
Igleside	Yes	The original term inferred that the problem detected was correctible through follow-up

Organization	Yes or No	Question 2 Comment
Cogeneration LP		maintenance -which is not always the case. The term “Unresolved Maintenance Issue” is more appropriate.
Response: Thank you for your comment.		
Springfield Utility Board	Yes	This change has no impact on how Springfield Utility Board currently operates.
Response: Thank you for your comment.		
Dominion	Yes	
FirstEnergy	Yes	
Southwest Power Pool Standards Review Group	Yes	
Florida Municipal Power Agency	Yes	
NERC Staff Technical Review	Yes	
Pepco Holdings Inc & Affiliates	Yes	
ACES Power	Yes	

Organization	Yes or No	Question 2 Comment
Collaborators		
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Tacoma Power	Yes	
Western Area Power Administration	Yes	
PacifiCorp	Yes	
Saft America, Inc.	Yes	
Nebraska Public Power District	Yes	
Exelon	Yes	
Dynegy Inc.	Yes	
Lincoln Electric System	Yes	
Entergy Services	Yes	

Organization	Yes or No	Question 2 Comment
Liberty Electric Power LLC	Yes	
Ameren	Yes	
Northeast Utilities	Yes	
Manitoba Hydro	Yes	
American Transmission Company	Yes	
ITC Holdings	Yes	
Oncor Electric Delivery Company LLC	Yes	
City of Austin dba Austin Energy	Yes	
Bonneville Power Administration	No	BPA agrees that the term “Maintenance Correctable Issue” is an improvement over “Unresolved Maintenance Issue”, however, BPA feels that the idea of a “Maintenance Correctable Issue” is very vague, and would perhaps be better left out of the standard. As written, it is unclear when an issue is a “Maintenance Correctable Issue” and exactly how it has to be dealt with. R3 requires the initiation of resolution of any unresolved

Organization	Yes or No	Question 2 Comment
		maintenance issues.
Response: Thank you for your comment. **The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues.**		
MRO's NERC Standards Review Forum	No	Requirement R3 includes the following: "and initiate resolution of any unresolved maintenance issues". The addition of unresolved maintenance issues to the standard is not included in the SAR and has the potential to cause confusion and misinterpretation. It is suggested that this phrase be removed.
Response: Thank you for your comment. The SAR was developed and submitted by the NERC System Protection and Control Task Force (SPCTF) who later prepared and submitted the Technical Reference "Protection System Maintenance" as a guide for the SDT to use in developing PRC-005-2. In crafting the elements of PRC-005-2, the SDT has endeavored to follow the SAR, which directs addressing FERC Order 693 directives; recommendations from the SPCTF Assessment of Standards PRC-005-1, PRC-008-0, PRC-011-0, PRC-017-0; and consideration of stakeholder comments received during the development of the Version 0 and Phase III & IV standards. **In the Detailed Description section of the SAR, bullet point four recommends the SDT define the terms "maintenance programs" and "testing programs" while recognizing other terms may be necessary for clarity. The SPCTF Assessment further recommends that PRC-005-2 "…should clarify that two goals are being covered: The maintenance portion should have requirements that keep the protection system equipment operating within manufacturers' design specifications throughout the service life" and the "testing portion should… verify the functional performance of protection systems". Additionally, in the SPCTF Technical Reference "Protection System Maintenance", the term "maintenance" is defined as "An ongoing program by which Protection System function is proved, and restored if needed."** **The SDT developed and defined the term "Protection System Maintenance Program" (PSMP) and its elements (which includes the testing portion) to achieve the goal of the recommendations of the SAR, SPCTF Assessment, and guidance given in the SPCTF Technical Reference. Consistent with this guidance, a PSMP is defined in PRC-005-2 as "An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored." The term "Unresolved Maintenance Issue" defines those things identified as needing follow-up action in order to restore them to proper**		

Organization	Yes or No	Question 2 Comment
operation. This may include repair or replacement activities that cannot be performed during the periodic PSMP activity through which the deficiency was discovered. Demonstrating the entity has initiated resolution of these issues might then include such things as documentation of a work order, replacement component order, invoice, or purchase order, etc… For clarity, the SDT has included these examples in the associated Measure for this requirement in the current draft. **The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues.**		
Southern Company Generation	No	The measure associated with the requirement that includes this term is non-specific with regards to what an auditor will require as proof of the initiation of resolving the issue. It is suggested that one of these two courses be followed: either a) eliminate the requirement to initiate resolution, or b) fully describe what evidence is expected for this part.
Response: Thank you for your comment. The SDT believes that an effective PSMP must include correction of deficiencies, but management of completion of any Unresolved Maintenance Issues is a complex topic which may involve a wide variety of activities (with varying completion timelines). The associated Measure lists examples of what may be effective evidence (more examples have been added); specific evidence, for any specific situation, will vary based on the particulars of that situation. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues.		
American Electric Power	No	The definition's wording is satisfactory, and we agree with the removal of "failure of a component to operate within design parameters". However, we do not agree with the use of the word "unresolved" within the term itself, as we believe this word may convey that the issue was not known or identified. We suggest replacing "Unresolved Maintenance Issue" with "Corrective Maintenance Issue".
Response: Thank you for your comment. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues.		

Organization	Yes or No	Question 2 Comment
Southern Company Transmission	No	The measure associated with the requirement that includes this term is non-specific with regards to what an auditor will require as proof of the initiation of resolving the issue. It is suggested that one of these two courses be followed: either a) eliminate the requirement to initiate resolution, or b) fully describe what evidence is expected for this part.
Response: Thank you for your comment. **The SDT believes that an effective PSMP must include correction of deficiencies, but management of completion of any Unresolved Maintenance Issues is a complex topic which may involve a wide variety of activities (with varying completion timelines). The associated Measure lists examples of what may be effective evidence (more examples have been added); specific evidence, for any specific situation, will vary based on the particulars of that situation. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues.**		
BGE	No	No comment about the change itself, but the terms were not consistently applied in the Supplemental Reference Manual (see last comment).
Response: Thank you for your comment. The SDT has further reviewed and revised the Supplementary Reference and FAQ document to facilitate consistent use of the terms.		
Constellation Power Generation	No	As R3 is currently written, Constellation Power Generation is concerned that this requirement may decrease the reliability of the BES under certain circumstances. The severity of the "deficiency" found will dictate the method and timing of a "follow up correction action". For a generator, the corrective action may not be "initiated" until the next planned outage, which may be a few years. However, R3 suggests that to comply, a generation site may have to extend an outage or take a forced and unplanned outage, to perform the corrective action. This would decrease the available resources in a given BA's footprint and potentially decrease the reliability of the BES.
Response: Thank you for your comment. **PRC-005-2 only requires the entity "… *initiate resolution*" of the issue found. The SDT recognizes that performance of the activities**		

Organization	Yes or No	Question 2 Comment
necessary to <u>resolve</u> an issue are entirely dependent upon the circumstances surrounding that issue and, consequently, will require varying amounts of resources and time to complete the process. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues. Demonstrating the entity has initiated resolution can include such things as documentation of a work order, replacement component order, invoice, or purchase order, etc… Producing evidence of this nature would then indicate adherence to the requirement.		
Constellation Energy Commodities Group	No	As R3 is currently written, Constellation Energy Commodities Group is concerned that this requirement may decrease the reliability of the BES under certain circumstances. The severity of the "deficiency" found will dictate the method and timing of a "follow up correction action". For a generator, the corrective action may not be "initiated" until the next planned outage, which may be a few years. However, R3 suggests that to comply, a generation site may have to extend an outage or take a forced and unplanned outage, to perform the corrective action. This would decrease the available resources in a given BA's footprint and potentially decrease the reliability of the BES.
Response: Thank you for your comment. **PRC-005-2 only requires the entity "… *<u>initiate</u> resolution*" of the issue found. The SDT recognizes that performance of the activities necessary to <u>resolve</u> an issue are entirely dependent upon the circumstances surrounding that issue and, consequently, will require varying amounts of resources and time to complete the process. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues. Demonstrating the entity has initiated resolution can include such things as documentation of a work order, replacement component order, invoice, or purchase order, etc… Producing evidence of this nature would then indicate adherence to the requirement.**		
PNGC Comment Group	No	
Central Lincoln		Either term works if defined properly.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment.		

3. **In response to comments, the SDT revised the previous "3 calendar months" interval to "4 calendar months" for communications systems and station dc supply. Do you agree with this change? If you do not agree, please provide specific suggestions for improvement.**

Summary Consideration: Most commenters agreed with the change; however, several commenters suggested further extension of these intervals. The SDT did not make any further changes to those intervals, explaining their belief that the established intervals are appropriate maximum intervals for this continent-wide standard. A few commenters continued to object to the establishment of maximum allowable intervals as specified in FERC Order 693; the SDT did not adopt any related suggestions, and instead reminded the commenters of FERC's directives.

Organization	Yes or No	Question 3 Comment
CPS Energy	Affirmative Ballot	The 4 month maintenance and testing interval for station DC supply is too short based on programs that have been in service for many years where twelve months have been proven as reliable for operation.
Response: Thank you for your comments **This 4 month interval is an "inspect and verify" activity not testing. FERC Order 693 and the approved SAR direct the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The SDT believes that the intervals established within the Tables are appropriate as continent-wide maximum allowable intervals, with due consideration for any monitoring functionality that may be present (per Table 1-4f).**		
Occidental Chemical	Affirmative Ballot	In response to comments, the SDT revised the previous "3 calendar months" interval to "4 calendar months" for communications systems and station dc supply. Do you agree with this change? If you do not agree, please provide specific suggestions for improvement. Yes. Ingleside Cogeneration LP agrees that the intervals on the activities in question should be extended to 4 calendar months. However on Page 20 of the Supplementary Reference document, the calculation of the next due date using units of "calendar months" is inconsistent with the calculation using a "calendar year". In the case of "calendar years", an activity must take place somewhere between Jan 1 and Dec 31. For "four calendar months", a follow-up activity must be performed within four months from the completion of the prior one. We believe that "four

Organization	Yes or No	Question 3 Comment
		calendar months" should be calculated in the same manner as a "calendar year". This means that an activity should take place at least once between January 1 and April 30; and repeated once during May 1 through August 31, and again between September 1 and December 31. The pattern would continue in ongoing years. Not only is this method consistent with the "calendar year" derivation, it allows the most flexibility in scheduling – especially if an unexpected event causes a delay. The vast majority of the maintenance activities will still take place at four months plus or minus a week or two; with an occasional outlier that adds minimal risk to reliability.
Response: Thank you for your comments. **Section 7.1 of the Supplementary Reference and FAQ document has been modified in consideration of your comment.**		
Wisconsin Electric Power Co. Wisconsin Electric Power Marketing	Affirmative Ballot	Focusing on batteries which are required to be done on a time-based maintenance program: 1. The big picture is that it is not just testing anymore - there are many more mandated tasks to be performed - Table 1-4(a). - Verifications & inspections are now part of the plan criteria, and have been moved from 3 months to a 4 month maximum interval. 2. We would like to see clarification on what is meant by the extent of 4 months. Is it by the end of the same calendar day or the previous calendar day, four months later; or is it 120 days or what? Could plan to manage to every 3 months, but not greater than 4 months. Same for Battery testing - manage to 1 year, but not greater than 18 months. 3. What is meant by battery continuity? Is battery float current an acceptable test methodology? It is not defined as clearly as an "impedance" or "resistance" test.
Response: Thank you for your comments. **1. The SDT believes that all of the maintenance activities within the "definition" of PSMP and as listed in the Tables are necessary components of an effective PSMP. Testing alone cannot assure that the Protection System components are in good working order.** **2. Section 7.1 of the Supplementary Reference and FAQ document provides an expanded discussion of this topic, and has been revised to add further clarity.**		

Organization	Yes or No	Question 3 Comment
3. **"Continuity" can be tested via several methods, and is described in detail in Section 15.4 of the Supplementary Reference and FAQ document. Battery float current is one of the many methods discussed within the Supplementary Reference Document.**		
PNGC Comment Group	Yes	We agree with this change. Smaller utilities, especially in the WECC region, in many cases have large territories to cover with limited resources. In many instances sub-stations are inaccessible during the winter and the 4 month interval will assist these smaller entities in getting the work done.
Response: Thank you for your comment		
MRO's NERC Standards Review Forum	Yes	We agree 4 calendar months is better than 3 Calendar months. The 4 month activities should be removed from Tables 1-4(a, b, c, d). These requirements are blurring the distinction between a best practice and functionally verifying the component. IEEE already sets the industries best practices, if a Reliability Standard includes best maintenance practices it is encroaching on IEEE's ability to keep the industry informed and optimized. The Standard Drafting Team should restrain itself to only making requirements that functionally verify components and initiate corrective action wherever possible. We recommend that this time frame be a maximum of 6 Calendar Months which will allow entities to establish their own time frame based on the seasonal changes that occur where the batteries are located.
Response: Thank you for your comments. **Station dc supply (including station batteries) must perform properly for the Protection System to function correctly. In order to establish that station batteries are functioning properly, the SDT believes that all of the listed maintenance activities must be performed, within the specified maximum intervals, with due consideration for any monitoring functionality that may be present. The SDT has drawn from the relevant IEEE standards (and other sources) to determine those activities that it has deemed appropriate to assure proper performance of the station battery. The SDT specifically believes that the 4-month maximum interval is proper for these activities for unmonitored DC supply systems and is consistent with the prevailing industry practice.**		
Tacoma Power	Yes	A similar change in interval should be applied to intervals of "6 calendar months".

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments **The SDT believes that the six-month interval is appropriate.**		
Nebraska Public Power District	Yes	We agree 4 calendar months is better than 3 Calendar months. The 4 month activities should be removed from Tables 1-4 (a, b, c, d). These requirements are blurring the distinction between a best practice and functionally verifying the component. IEEE already sets the industries best practices, if a Reliability Standard includes best maintenance practices it is encroaching on IEEE's ability to keep the industry informed and optimized. The Standard Drafting Team should restrain itself to only making requirements that functionally verify components and initiate corrective action wherever possible.
Response: Thank you for your comments. **Station dc supply (including station batteries) must perform properly for the Protection System to function correctly. In order to establish that station batteries are functioning properly, the SDT believes that all of the listed maintenance activities must be performed, within the specified maximum intervals. The SDT has drawn from the relevant IEEE standards (and other sources) to determine those activities that it has deemed appropriate to assure proper performance of station batteries. The SDT specifically believes that the 4-month maximum interval is proper for these activities for unmonitored DC supply systems and is consistent with the prevailing industry practice.**		
Central Lincoln	Yes	Thank you for making this change. As we pointed out in draft 2, a three month maximum would require a bi-monthly target to allow for contingencies; increasing maintenance from four times a year (per the IEEE battery standards) to six.
Response: Thank you for your comment.		
Ameren	Yes	Our experience with a very large number of communication systems and station dc supplies substantiates an even longer interval as sufficient for reliable Protection Systems.
Response: Thank you for your comment. If your experience suggests that longer intervals for communications systems will produce appropriate performance, you may employ performance-based maintenance (per the draft standard). However, SDT		

Organization	Yes or No	Question 3 Comment
believes that all of the listed maintenance activities for station dc supply must be performed, within the specified maximum intervals, with due consideration for any monitoring functionality that may be present.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP agrees that the intervals on the activities in question should be extended to 4 calendar months. However on Page 20 of the Supplementary Reference document, the calculation of the next due date using units of “calendar months” is inconsistent with the calculation using a “calendar year”. In the case of “calendar years”, an activity must take place somewhere between Jan 1 and Dec 31. For “four calendar months”, a follow-up activity must be performed within four months from the completion of the prior one. We believe that “four calendar months” should be calculated in the same manner as a “calendar year”. This means that an activity should take place at least once between January 1 and April 30; and repeated once during May 1 through August 31, and again between September 1 and December 31. The pattern would continue in ongoing years. Not only is this method consistent with the “calendar year” derivation, it allows the most flexibility in scheduling - especially if an unexpected event causes a delay. The vast majority of the maintenance activities will still take place at four months plus or minus a week or two; with an occasional outlier that adds minimal risk to reliability.
Response: Thank you for your comments. Section 7.1 of the Supplementary Reference and FAQ document provides an expanded discussion of this topic, and has been revised to add further clarity.		
BGE	Yes	BGE appreciates the SDT demonstrating flexibility by extending these maintenance intervals.
Response: Thank you for your comment.		
Springfield Utility Board	Yes	This change has no impact on how Springfield Utility Board currently operates.
Response: Thank you for your comment.		
MidAmerican Energy	Yes	None

Organization	Yes or No	Question 3 Comment
Company		
Bonneville Power Administration	Yes	
Dominion	Yes	
FirstEnergy	Yes	
Southwest Power Pool Standards Review Group	Yes	
Florida Municipal Power Agency	Yes	
Pepco Holdings Inc & Affiliates	Yes	
ACES Power Collaborators	Yes	
Southern Company Generation	Yes	
Westar Energy	Yes	

Organization	Yes or No	Question 3 Comment
Progress Energy	Yes	
Western Area Power Administration	Yes	
PacifiCorp	Yes	
Saft America, Inc.	Yes	
Exelon	Yes	
Dynegy Inc.	Yes	
Lincoln Electric System	Yes	
Entergy Services	Yes	
Independent Electricity System Operator	Yes	
Liberty Electric Power LLC	Yes	
American Transmission	Yes	

Organization	Yes or No	Question 3 Comment
Company		
Southern Company Transmission	Yes	
ITC Holdings	Yes	
Oncor Electric Delivery Company LLC	Yes	
City of Austin dba Austin Energy	Yes	
Northeast Utilities	Yes	
Manitoba Hydro	No	Manitoba Hydro maintains that the battery inspection interval should be extended to 6 months. The 4 month interval is too frequent based on our experience and while IEEE std 450 (which seems to be the basis for table 1-4) does recommend intervals, it also states that users should evaluate these recommendations against their own operating experience. Our experience shows that 6 month battery inspections are more than adequate to maintain system reliability.Manitoba Hydro has more than ten years of experience using its existing battery inspection intervals, and Manitoba Hydro's reliability data has proven that the 6 month inspection interval is suitable for Manitoba Hydro. Manitoba Hydro's battery maintenance tasks were derived from a reliability study of Manitoba Hydro stationary batteries, and the tasks and intervals are suitable given Manitoba Hydro's installed plant, design criteria, climate, and reliability performance. A more frequent inspection interval might be more suitable to specific utilities with material differences in climate, design, installed apparatus, and performance, but it is not suitable for Manitoba Hydro

Organization	Yes or No	Question 3 Comment
		and may be more than is required for many other utilities. To use a more frequent inspection interval would significantly penalize Manitoba Hydro which has been diligently performing battery inspections for many years, with no resulting increase in reliability. With the 4 month battery check frequency and no allowance for a grace period, there may be a negative impact on reliability caused by diverting resources away from projects that are critical to reliability to meet this maintenance interval.
Response: Thank you for your comments. **This 4 month interval is an "inspect and verify" activity not testing. FERC Order 693 and the approved SAR direct the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The SDT believes that the intervals established within the Tables are appropriate as continent-wide maximum allowable intervals, with due consideration for any monitoring functionality that may be present (per Table 1-4f).**		
Arizona Public Service Company	No	APS has been testing batteries nominally every 4 months plus 25% for over 20 years with no adverse consequences. Requiring a maximum of testing every 4 months doesn't allow for any flexibility, would require an additional 400 tests per year and APS does not consider the 4 months a maximum time limit for battery testing.
Response: Thank you for your comments. **This 4 month interval is an "inspect and verify" activity not testing. FERC Order 693 and the approved SAR direct the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The SDT believes that the intervals established within the Tables are appropriate as continent-wide maximum allowable intervals, with due consideration for any monitoring functionality that may be present (per Table 1-4f).**		
Utility Services, Inc	No	The standard should provide guidance what tasks need to be accomplished for compliance and not mandates on specifics like this. Registered Entities should be left to determine the appropriate intervals based upon their experience and good utility practices.
Response: Thank you for your comments **FERC Order 693 and the approved SAR direct the SDT to develop a standard with maximum allowable intervals and minimum**		

Organization	Yes or No	Question 3 Comment
maintenance activities. The SDT believes that the intervals established within the Tables are appropriate as continent-wide maximum allowable intervals, with due consideration for any monitoring functionality that may be present. If an entity's experience is that some components require less-frequent maintenance than specified in the Tables, a performance-based program in accordance with Requirement R2 and Attachment A is an option unless specifically precluded.		
American Electric Power	No	Though we agree with extending the interval from what it was previously, AEP recommends that the interval in Table 1-2 for Communications Systems be increased to 6 months.
Response: Thank you for your comments **The SDT believes that the revised 4-month maximum interval is proper for unmonitored communications systems.**		
Tennessee Valley Authority	No	

4. **The SDT extracted the maintenance activities and intervals for distributed UFLS and UVLS systems from Table 1-1 through 1-5 and placed them into a new Table 3 to more clearly illustrate the requirements related to these systems. Do you agree with this change? If you do not agree, please provide specific suggestions for improvement.**

Summary Consideration: Most commenters appreciated the break-out of distributed UFLS/UVLS maintenance activities into Table 3. Several commenters, however, continued to object to inclusion of this maintenance within the standard, and some questioned NERC's jurisdiction to address devices installed on the distribution system. The SDT consulted with NERC legal staff on the jurisdiction question, and cited the position from NERC Legal in responding that these devices are indeed within NERC's authority because they are installed for the reliability of the BES. Several commenters also objected to the requirements relating to periodic operation of electromechanical devices, maintenance of voltage and current sensing devices, and/or maintenance of the dc supply within the new Table 3, and the SDT provided responses supporting the SDT's belief that all of these activities are relevant and necessary for inclusion within the standard. Several other commenters suggested formatting changes, most of which were adopted. While considering these comments, the SDT also made assorted clarifying changes to Table 3.

Organization	Yes or No	Question 4 Comment
Occidental Chemical	Affirmative Ballot	The SDT extracted the maintenance activities and intervals for distributed UFLS and UVLS systems from Table 1-1 through 1-5 and placed them into a new Table 3 to more clearly illustrate the requirements related to these systems. Do you agree with this change? If you do not agree, please provide specific suggestions for improvement. Yes. We believe that distributed UFLS and UVLS relay systems have a very different operating purpose than those that are not distributed. It is appropriate to separate the maintenance activities and intervals for these relay systems.
Response: Thank you for your support.		
Southern Company Generation	Yes	1. Separating this classification of equipment into its own table is a good idea to make it easier for the owners of this equipment to figure out what they must do. 2. Consider also moving the UVLS note (found in column 1 of Tables 1-4a-d) into the header with

Organization	Yes or No	Question 4 Comment
		the other "UFLS and UVLS note" to simplify the table. The header note could read "Excludes UFLS and UVLS systems - see Table 1-4e for non-distributed UFLS and UVLS systems and see Table 3 for distributed UFLS and UVLS systems"). 3. Table 1-5: Need clarification on "continuity and energization or ability to operate". What does this mean? 4. For UF and UV schemes, Table 3 does not specifically state to check the alarm(s) to a control center (for monitored components). There are some references to Table 2 (i.e. See Table 2), but does that mean that you have to verify the alarm(s)? We think that the Table 2 details need to be included specifically in Table 3. Or, make it very clear that this test is required for UF and UV schemes.
Response: **1. Thank you for your support.** **2. Thank you for your comment, Table 1-4 (a, b, c, d) has been revised accordingly.** **3. This entry in Table 1-5 has been modified to "Control circuitry whose integrity is monitored and alarmed". Section 15.3 of the Supplementary Reference and FAQ document provides additional discussion on this topic.** **4. The SDT has revised the Table 2 for clarity.**		
Ameren	Yes	Please consistently state UFLS before UVLS; Table 1-4(e) differs from other parts of the standard.
Response: Thank you for your suggestion; the SDT has revised the standard.		
Northeast Utilities	Yes	The migration of the UFLS and UVLS requirements to Table 3 is appreciated. The Table 3 Component Attributes in rows 6 and 7 ("Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices" and Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems" respectively) do not identify that the trip coils are excluded. Although row 9 states "Trip coils of non-BES interrupting devices in UFLS or UVLS systems" do not have any period maintenance specified, our recommendation is to

Organization	Yes or No	Question 4 Comment
		annotate rows 6 and 7 to explicitly indicate the trip coils are excluded.
Response: Thank you for support. The SDT has revised Table 3 accordingly.		
MidAmerican Energy Company	Yes	None
Southern Company Transmission	Yes	For UF and UV schemes, Table 3 does not specifically state to check the alarm(s) to a control center (for monitored components). There are some references to Table 2 (i.e. See Table 2), but does that mean that you have to verify the alarm(s)? I think Table 2 details need to be included specifically in Table 3. Or make it very clear that this test is required for UF and UV schemes.
Response: Thank you for your comment. The SDT has revised Table 2 for clarity.		
Ingleside Cogeneration LP	Yes	We believe that distributed UFLS and UVLS relay systems have a very different operating purpose than those that are not distributed. It is appropriate to separate the maintenance activities and intervals for these relay systems.
Response: Thank you for your support.		
Springfield Utility Board	Yes	Although numerous tables can become overwhelming to navigate, it is far less ambiguous if specific systems are spelled out in separate and distinct tables.
Response: Thank you for your support.		
Ameren	Yes	Please consistently state UFLS before UVLS; Table 1-4(e) differs from other parts of the standard.
Response: Thank you for your suggestion. The SDT has revised the standard.		
Oncor Electric Delivery	Yes	

Organization	Yes or No	Question 4 Comment
Company LLC		
City of Austin dba Austin Energy	Yes	
PNGC Comment Group	Yes	
Bonneville Power Administration	Yes	
Dominion	Yes	
FirstEnergy	Yes	
Southwest Power Pool Standards Review Group	Yes	
City of Austin dba Austin Energy	Yes	
Pepco Holdings Inc & Affiliates	Yes	
MRO's NERC Standards	Yes	

Organization	Yes or No	Question 4 Comment
Review Forum		
ACES Power Collaborators	Yes	
Arizona Public Service Company	Yes	
Westar Energy	Yes	
Tacoma Power	Yes	
Progress Energy	Yes	
Western Area Power Administration	Yes	
PacifiCorp	Yes	
Saft America, Inc.	Yes	
Nebraska Public Power District	Yes	
Exelon	Yes	
Texas Reliability Entity	Yes	

Organization	Yes or No	Question 4 Comment
Central Lincoln	Yes	
Dynegy Inc.	Yes	
American Electric Power	Yes	
Lincoln Electric System	Yes	
Entergy Services	Yes	
Independent Electricity System Operator	Yes	
Liberty Electric Power LLC	Yes	
Manitoba Hydro	Yes	
American Transmission Company	Yes	
Utility Services, Inc	Yes	

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td>ITC Holdings</td><td>Yes</td><td></td></tr>
<tr><td>Flathead Electric Cooperative</td><td>Negative Ballot</td><td>I appreciate the drafting team’s effort to separate requirements for distributed UFLS, however fundamentally it is unclear how mandatory and enforceable requirements can be applied to non-BES elements as there is no statutory authority over local distribution networks.</td></tr>
<tr><td colspan="3">Response: Thank you for comment. In regards to your concern, the SDT received the following position from NERC Legal:

“While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC’s 215 authority.

FPA section 215(a) definitions section defines “bulk-power system as (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof).” That definition then is limited by a later statement which adds the term bulk-power system “does not include facilities used in the local distribution of electric energy.” Also, section 215 also covers users, owners, and operators of bulk-power facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not “used in the local distribution of electric energy” despite their location on local distribution networks. Further, if UFLS/UVLS facilities were not covered by the Reliability Standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that load would have to be shed at the transmission bus to ensure the load-generation balance and voltage stability is maintained on the BES.”</td></tr>
<tr><td>Lakeland Electric</td><td>Negative Ballot</td><td>The standard reaches further into the distribution system for UFLS and UVLS. It will be burdensome to present all the evidence of distribution class protection system maintenance and testing at audits.</td></tr>
<tr><td colspan="3">Response: The existing standards (PRC-008 & PRC-011) already require maintenance and testing of components of UFLS and UVLS protection systems, including those installed to operate distribution-level interrupting devices.</td></tr>
<tr><td>Beaches Energy</td><td>Negative</td><td>The standard reaches further into the distribution system than we would like for UFLS and UVLS</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
Services	Ballot	(Table 3). We have two parts to this concern. First, it will be somewhat onerous to present all the evidence of distribution class protection system maintenance and testing at audits. And second, our biggest concern is in the testing required to "exercise" a lockout or tripping relay. This may require installation of test blocks to allow such exercising of the lockout or tripping relay without tripping the distribution circuit, and such a test could be difficult to perform without impacting customer continuity of service if the lockout/tripping relay for the UFLS is the same as the lockout/tripping relay for distribution fault protection.

Response: Thank you for your comment.

First, the existing standards (PRC-008 & PRC-011) already require maintenance and testing of components of UFLS and UVLS protection systems, including those installed to operate distribution-level interrupting devices.

Second, the UVLS and UFLS systems are included as part of the Project 2007-17 Standard Authorization Request (SAR). The SDT believes that electromechanical devices, such as auxiliary or lockout relays which contain “moving parts”, need periodic operation in order to remain reliable. As such, these devices are required to be exercised at the 12 year interval for UVLS and UFLS systems. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed.

Organization	Yes or No	Question 4 Comment
Florida Keys Electric Cooperative Assoc.	Negative Ballot	The standard reaches further into the distribution system than we would like for UFLS and UVLS (Table 3). We have two parts to this concern. First, it will be somewhat onerous to present all the evidence of distribution class protection system maintenance and testing at audits. And second, our biggest concern is in the testing required to "exercise" a lockout or tripping relay. This may require installation of test blocks to allow such exercising of the lockout or tripping relay without tripping the distribution circuit, and such a test could be difficult to preform without impacting customer continuity of service if the lockout/tripping relay for the UFLS is the same as the lockout/tripping relay for distribution fault protection. However, most of FMPA's members have microprocessor-based relays for distribution circuits with the UFLS / UVLS embedded within the microprocessor based relay where the path from the UFLS / UVLS relay to the lockout / tripping relay is internal to the micro-processor based relay, so, testing the UFLS/UVLS relay will at the same time test the internal lockout / switching relay. However, for older electro-mechanical UFLS schemes, this type of testing could be problematic.
Response: Thank you for your comment. **First, the existing standards (PRC-008 & PRC-011) already require maintenance and testing of components of UFLS and UVLS protection systems, including those installed to operate distribution-level interrupting devices.** **Second, the UVLS and UFLS systems are included as part of the Project 2007-17 Standard Authorization Request (SAR). The SDT believes that electromechanical devices, such as auxiliary or lockout relays which contain "moving parts", need periodic operation in order to remain reliable. As such, these devices are required to be exercised at the 12 year interval for UVLS and UFLS systems. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed.**		

Organization	Yes or No	Question 4 Comment
Florida Municipal Power Agency	Negative Ballot Negative Poll	The standard reaches further into the distribution system than we would like for UFLS and UVLS (Table 3). We have two parts to this concern. First, it will be somewhat onerous to present all the evidence of distribution class protection system maintenance and testing at audits. And second, our biggest concern is in the testing required to "exercise" a lockout or tripping relay. This may require installation of test blocks to allow such exercising of the lockout or tripping relay without tripping the distribution circuit, and such a test could be difficult to preform without impacting customer continuity of service if the lockout/tripping relay for the UFLS is the same as the lockout/tripping relay for distribution fault protection. However, most of FMPA's members have microprocessor-based relays for distribution circuits with the UFLS / UVLS embedded within the microprocessor based relay where the path from the UFLS / UVLS relay to the lockout / tripping relay is internal to the micro-processor based relay, so, testing the UFLS/UVLS relay will at the same time test the internal lockout / switching relay. However, for older electro-mechanical UFLS schemes, this type of testing could be problematic. Borderline concerning whether this causes us to vote Negative or not. As a result, FMPA recommends a Negative vote with the second and third comments, emphasizing that it is the second comment that causes us to vote negative but we also would like the 3rd comment addressed. Feedback appreciated. Vote and comments are due next Wednesday, 9/28.

Response: Thank you for your comment.

First, the existing standards (PRC-008 & PRC-011) already require maintenance and testing of components of UFLS and UVLS protection systems, including those installed to operate distribution-level interrupting devices.

Second, the UVLS and UFLS systems are included as part of the Project 2007-17 Standard Authorization Request (SAR). The SDT believes that electromechanical devices, such as auxiliary or lockout relays which contain “moving parts”, need periodic operation in order to remain reliable. As such, these devices are required to be exercised at the 12 year interval for UVLS and UFLS systems. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed.

Organization	Yes or No	Question 4 Comment
Florida Municipal Power Pool	Negative Ballot Negative Poll	The standard reaches further into the distribution system than we would like for UFLS and UVLS (Table 3). We have two parts to this concern. First, it will be somewhat onerous to present all the evidence of distribution class protection system maintenance and testing at audits. And second, our biggest concern is in the testing required to "exercise" a lockout or tripping relay. This may require installation of test blocks to allow such exercising of the lockout or tripping relay without tripping the distribution circuit, and such a test could be difficult to preform without impacting customer continuity of service if the lockout/tripping relay for the UFLS is the same as the lockout/tripping relay for distribution fault protection. However, most of FMPA's members have microprocessor-based relays for distribution circuits with the UFLS / UVLS embedded within the microprocessor based relay where the path from the UFLS / UVLS relay to the lockout / tripping relay is internal to the micro-processor based relay, so, testing the UFLS/UVLS relay will at the same time test the internal lockout / switching relay. However, for older electro-mechanical UFLS schemes, this type of testing could be problematic. Borderline concerning whether this causes us to vote Negative or not.
Response: Thank you for your comment. **First, the existing standards (PRC-008 & PRC-011) already require maintenance and testing of components of UFLS and UVLS protection systems, including those installed to operate distribution-level interrupting devices.** **Second, the UVLS and UFLS systems are included as part of the Project 2007-17 Standard Authorization Request (SAR). The SDT believes that electromechanical devices, such as auxiliary or lockout relays which contain "moving parts", need periodic operation in order to remain reliable. As such, these devices are required to be exercised at the 12 year interval for UVLS and UFLS systems. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be manageds.**		
Lincoln Electric System	Negative Ballot	Please see comments submitted in addition to the following comment. LES recommends the standard drafting team clarify the expected maintenance activities for BES related batteries that also serve UFLS systems. In particular, what would be the required maintenance activities for a battery bank serving both BES transmission elements and UFLS elements? Table 1.4 clearly

Organization	Yes or No	Question 4 Comment
		excludes UFLS elements and Table 3 indicates it only applies to “non-BES interrupting devices”. As such, if a joint use battery is excluded from Table 1.4 because of its association with UFLS, BES related batteries would have no place in any of the tables.
Response: Thank you for your comment. **The SDT responded to your other comments in the sections where they were submitted.** **A battery bank serving both BES and UFLS/UVLS protection systems would be maintained per table 1-4. A battery bank that serves only distributed UFLS or UVLS system would be maintained per table 3.** **The headers of the various sections of Table 1-4 now exclude station dc supply that is used <u>only</u> for UFLS/UVLS from Table 1-4.**		
CenterPoint Energy	No	1. For the “Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices”, the Table 3 requirement is to “Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic)” every 12 calendar years. CenterPoint Energy recommends this requirement be revised to “No periodic maintenance specified”. CenterPoint Energy believes that wire checking a panel is a commissioning task, not a preventive maintenance task. CenterPoint Energy performs such checks on new stations and whenever expansion or modification of existing stations dictates such testing. 2. In addition, CenterPoint Energy recommends the requirement in Table 3 to “Verify that current and/or voltage signal values are provided to the protective relays” every 12 years be revised to “No periodic maintenance specified”. 3. Likewise, we recommend the requirement in Table 3 to “Verify Protection System dc supply voltage” every 12 years be revised to “No periodic maintenance specified”. Preventive maintenance tasks such as the three above are unnecessary for distributed UFLS and UVLS system components. The overriding performance, or “risk-based”, NERC Reliability Standards for UFLS are PRC-006 and PRC-007 where an entity is required to shed their obligated firm load amount.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comment. **1. While much of the control circuitry associated with a distribution device is regularly exercised, the SDT believes that the control circuitry associated directly with UFLS/UVLS that are applied for BES reliability need be periodically verified to assure that these components will function properly when called upon to do so.** **2. The SDT believes that the voltage/current signals that support proper operation of UFLS/UVLS that are applied for BES reliability need be periodically verified to assure that these components will function properly when called upon to do so. The specific degree of this verification is constrained within Table 3 to those activities necessary to assure proper operation of the UFLS/UVLS.** **3. The SDT believes that the station dc supply that supports only proper operation of UFLS/UVLS that are applied for BES reliability need be periodically verified to assure that these components will function properly when called upon to do so. The specific degree of this verification is constrained within Table 3 to only periodic measurement of the dc voltage.**		
BGE	No	Although BGE does not disagree with moving the distributed UFLS/UVLS maintenance activities and intervals into the new Table-3, BGE requests further clarification from the SDT on how to correctly interpret the headings and content of this table.
Response: Thank you for your support. Table 3 has been modified since it was last released for comment. Table 3 should be used to determine maintenance activities and intervals for distributed UFLS and UVLS systems. Distributed systems are further elaborated upon in the Supplementary Reference and FAQ document, Section 15.7.		
Constellation Power Generation	No	Moving the UFLS and UVLS systems from Tables 1-1 through 1-5 into a separate Table 3 is a useful improvement in illustrating the requirements. However, our objection is not really with the format, it is will the content of the Tables. From a generation perspective, the maintenance intervals and activities described in all of the Tables are too prescriptive and we are concerned that they may conflict with the existing PSMPs built by Registered Entities based on years of operational experience with the testing methods and testing frequencies that work best for the specific asset. In the worst case, the specifics dictated in the Tables may move Entities away from more stringent PSMPs that are currently in practice. For this reason, Constellation suggests that the drafting team revisit the concept of the Tables to better balance to convey useful guidance without creating a

Organization	Yes or No	Question 4 Comment
		compliance requirement that may be contrary to improved reliability. The Registered Entity should be given more flexibility to dictate how a protection system component should be tested, and at what frequency. Lastly, the technical manpower and compliance documentation demands to implement a performance based protection system maintenance program are so onerous that it is highly unlikely that any small generation entity would use it.
Response: Thank you for your comment. **FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The SDT believes that the intervals established within the Tables are appropriate as continent-wide maximum allowable intervals, with due consideration for any monitoring functionality that may be present. The ability to utilize performance-based maintenance is provided for those entities who wish to pursue it; it is understood that many entities may instead choose to simply implement a PSMP based on the Tables.**		
Constellation Energy Commodities Group	No	Moving the UFLS and UVLS systems from Tables 1-1 through 1-5 into a separate Table 3 is a useful improvement in illustrating the requirements. However, our objection is not really with the format, it is will the content of the Tables. From a generation perspective, the maintenance intervals and activities described in all of the Tables are too prescriptive and we are concerned that they may conflict with the existing PSMPs built by Registered Entities based on years of operational experience with the testing methods and testing frequencies that work best for the specific asset. In the worst case, the specifics dictated in the Tables may move Entities away from more stringent PSMPs that are currently in practice. For this reason, Constellation suggests that the drafting team revisit the concept of the Tables to better balance to convey useful guidance without creating a compliance requirement that may be contrary to improved reliability. The Registered Entity should be given more flexibility to dictate how a protection system component should be tested, and at what frequency. Lastly, the technical manpower and compliance documentation demands to implement a performance based protection system maintenance program are so onerous that it is highly unlikely that any small generation entity would use it.
Response: Thank you for your comment. **FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum**		

Organization	Yes or No	Question 4 Comment
maintenance activities. The SDT believes that the intervals established within the Tables are appropriate as continent-wide maximum allowable intervals, with due consideration for any monitoring functionality that may be present. The ability to utilize performance-based maintenance is provided for those entities who wish to pursue it; it is understood that many entities may instead choose to simply implement a PSMP based on the Tables.		
Florida Municipal Power Agency	No	We like the new Table 3, but, have remaining concerns. The standard reaches further into the distribution system than we would like for UFLS and UVLS. We have two parts to this concern. First, it will be somewhat onerous to present all the evidence of distribution class protection system maintenance and testing at audits. And second, our biggest concern is in the testing required to "exercise" a lockout or tripping relay. This may require installation of test blocks to allow such exercising of the lockout or tripping relay without tripping the distribution circuit, and such a test could be difficult to perform without impacting customer continuity of service if the lockout/tripping relay for the UFLS is the same as the lockout/tripping relay for distribution fault protection. However, most of FMPA's members have microprocessor-based relays for distribution circuits with the UFLS / UVLS embedded within the microprocessor based relay where the path from the UFLS / UVLS relay to the lockout / tripping relay is internal to the micro-processor based relay, so, testing the UFLS/UVLS relay will at the same time test the internal lockout / switching relay. However, for older electro-mechanical UFLS schemes, this type of testing could be problematic.
Response: Thank you for your comment. **First, the existing standards (PRC-008 & PRC-011) already require maintenance and testing of components of UFLS and UVLS protection systems, including those installed to operate distribution-level interrupting devices.** **Second, the UVLS and UFLS systems are included as part of the Project 2007-17 Standard Authorization Request (SAR). The SDT believes that electromechanical devices, such as auxiliary or lockout relays which contain “moving parts”, need periodic operation in order to remain reliable. As such, these devices are required to be exercised at the 12 year interval for UVLS and UFLS systems. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed.**		

Organization	Yes or No	Question 4 Comment
NERC Staff Technical Review	No	We agree in principle with the change; however, we have identified discrepancies among these tables with respect to the reference to UFLS and UVLS systems. The headings in Tables 1-1 through 1-4(b) and Table 1-5 refer to “Excluding distributed UFLS and UVLS”; Table 1-4(c) refers to “Excluding UFLS and non-distributed UVLS”; while Table 1-4(d) refers to “Excluding UFLS and distributed UVLS.” We believe the drafting team intended for consistency among these tables and that the intent is to exclude distributed UFLS and distributed UVLS schemes as opposed to distributed UFLS and all UVLS schemes. To make this clear we recommend changing the second line in the heading of each of these tables to “Excluding distributed UFLS and distributed UVLS.” Corresponding changes should be made in the “Component Attributes” sections of Tables 1-4(a) through 1-4(e) and to the title of Table 3.
Response: Thank you for your comment. The standard has been modified as you suggest.		
Tennessee Valley Authority	No	

5. The SDT has revised the "Supplementary Reference and FAQ" document which is supplied to provide supporting discussion for the Requirements within the standard. Do you agree with the changes? If not, please provide specific suggestions for change.

Summary Consideration: Many commenters objected to Requirement R3 and to the explanation that entities would be held to compliance on "either the Tables or their PSMP, whichever is more stringent". In response to these comments, the SDT modified the standard to remove Requirement R1 part 1.3, and revised Requirement R3 so that, for time-based programs, entities shall comply with the Tables rather than their PSMP. The SDT added Requirement R4 to address performance-based maintenance, and added Requirement R5 to address Unresolved Maintenance Issues. The Supplementary Reference and FAQ document was updated to reflect these changes.

Several commenters questioned the inclusion of the dc control circuitry for sudden pressure relays even though the relays themselves are excluded from the definition of "Protection System"; the SDT reiterated its position that this dc control circuitry is indeed included because the dc control circuitry is associated with protective functions. No change was made to the standard based on these comments.

Numerous commenters suggested minor revisions or clarifying text for the Supplementary Reference and FAQ document. These changes were generally adopted.

Organization	Yes or No	Question 5 Comment
Ameren Services	Affirmative Ballot	1. Although the explanation of 'Restore' is enlightening on page 12, 'Restore' no longer appears in the PS Maintenance definition in the last few drafts. 2. We disagree with the added burden of retaining maintenance records for removed or replaced equipment. This will actually reduce reliability because of the confusion it can cause as to what

Organization	Yes or No	Question 5 Comment
		equipment is providing BES protection. At most, only the last maintenance date of the removed or replaced component should be retained if there's really a need to prove that the interval was met regarding the BES protection. 3. Remove 'Reverse power relays' from the list on page 32. They provide thermal of the steam turbine, not electrical protection of the generator. 4. Now that FERC has approved the Project 2009-17 Interpretation, please acknowledge more directly in the Supplement that the 'transmission Protection System' that is now approved. NERC interprets "transmission Protection System," as it appears in Requirements R1 and R3 of PRC-004-1 and Requirements R1 and R2 of PRC-005-1, to mean "any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES". 5. Please consistently state UFLS before UVLS; Table 1-4(e) differs from other parts of the standard.

Response:

1. **Thank you for your suggestion; the SDT has revised the Supplementary Reference and FAQ document to remove the "restore" reference from the definition.**
2. **The records for removed/replaced equipment need to be retained to provide documentation that you were in compliance for the entire compliance monitoring period.**
3. **The SDT agrees that for many steam units, reverse power relays provide alarm only of a condition which could result in eventual overheating of steam turbine components. However, for many combustion turbine generators, a reverse power condition can lead to imminent failure of teeth on the speed reduction gear and thus, reverse power relays on combustion turbine generators are frequently wired as a direct trip to the generator breaker to immediately remove the motoring condition. Furthermore, in the Supplementary Reference document, the preface to the list of relays to which you refer is as follows: "Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay may include but are not necessarily limited to:". The SDT was attempting to provide a list of possible relays that might need to be included. The list is not meant to be all inclusive nor do all relays of the types on the list necessarily need to be included in an**

Organization	Yes or No	Question 5 Comment
entity's PSMP. 4. The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion. 5. Thank you for your suggestion; the SDT has revised the standard.		
Madison Gas and Electric Co.	Affirmative Ballot	Note that the Guidance document over states that an entity will be held accountable for have a more restrictive PMSP than the maximum intervals in attachment 1. Please review FERC Order 693, section 278 which states: "While we appreciate that many entities may perform at a higher level than that required by the Reliability Standards, and commend them for doing so, the Commission is focused on what is required under the Reliability Standards, and we do not require that they exceed the Reliability Standards".
Response: Thank you for your comment. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Northeast Power Coordinating Council, Inc.	Affirmative Ballot	An issue was raised here in the Northeast regarding requiring an entity to adhere to their protection system maintenance program, PSMP. If an entity has a maintenance program in place that has shorter intervals, i.e. more stringent than those in the appendix of the standard, and the entity misses completing his maintenance, the entity will be found non-compliant irrespective of the entity to demonstrate they still were within the longer intervals listed in the actual standard. NPCC would suggest that the SDT consider revising this to only result in a non-compliance assessment result if an entity missed the intervals in the appendix of the standard not those specified in their PSMP. The concern is that some entities will forego more stringent programs and revise their documents "downward" in order to ensure compliance at the potential for a reduction in reliability. There is no mechanism currently in place to preclude entities from doing this.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Occidental Chemical	Affirmative Ballot	The SDT has revised the “Supplementary Reference” document which is supplied to provide supporting discussion for the Requirements within the standard. Do you agree with the changes? If not, please provide specific suggestions for change. Yes. Ingleside Cogeneration LP found the Supplementary Reference document to be helpful, thorough, and technically accurate. The only suggestion we have is that demonstrated adherence to the Reference should be admissible of evidence of compliance at an audit or spot check. Today, all References have no official regulatory standing – which seems to defeat the purpose of developing them to begin with.
Response: Thank you for your comment. The document is explanatory but also illustrates the intent of the SDT. The rationale and methods explained within the Supplementary Reference and FAQ document represent the thoughts of the SDT regarding approaches to application of the standard, but may (or may not) be of use to demonstrate compliance. FERC approves standards as mandatory and enforceable; FERC does not approve reference documents.		
Occidental Chemical	Affirmative Ballot	We need to clarify the following: A transmission owner has established a maintenance cycle which is more stringent (less time between maintenance or test cycles) than the NERC Standard requires. The transmission owner fails to comply fully with the transmission owner's maintenance and testing schedule; however, the maintenance and/or testing is performed within the time frame mandated by the NERC Standard. Must the transmission owner report his failure to comply with his own maintenance/testing program even though the maintenance or testing was completed well within the time frame or interval required by the applicable NERC Standard? Must he transmission owner report such a failure of his own maintenance procedures which are more stringent than the NERC maintenance/testing standard? Will such a self report be considered a non-compliance?
Response: Thank you for your comment. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for		

Organization	Yes or No	Question 5 Comment
time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Oncor Electric Delivery Company LLC	Yes	Oncor would like to see the "Supplementary Reference & FAQ" expanded to provide examples of what documentation would satisfy that the entity is compliant with initiating "resolution of any Unresolved Maintenance Issues." Also it would be helpful to all entities if the Drafting Team would expand on what, if any, tracking of the resolution of an unresolved maintenance issue is required. Oncor believes that keeping track of the initiation of "resolution of any unresolved maintenance issues" is necessary but that the standard does not currently address retention requirements related to this compliance obligation.
Response: Thank you for your comment. The measure related to this requirement has been expanded to include additional suggestions of relevant documentation. There is no tracking requirement listed for the resolution of unresolved maintenance issue, only the initiation of a resolution. The SDT recognizes that performance of the activities necessary to <u>resolve</u> an issue are entirely dependent upon the circumstances surrounding that issue and, consequently, will require varying amounts of resources and time to complete the process. Requiring tracking and deadlines is not within the scope of this standard. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues.		
Springfield Utility Board	Yes	Because Springfield Utility Board's (SUB) current maintenance and testing program is time-based, the revised "Supplementary Reference" document does not impact SUB operations. SUB agrees with the document changes because the changes result in alternatives for entities, rather than being prescriptive.
Response: Thank you for your comment.		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP found the Supplementary Reference document to be helpful, thorough, and technically accurate. The only suggestion we have is that demonstrated adherence to the Reference should be admissible of evidence of compliance at an audit or spot check. Today, all References have no official regulatory standing - which seems to defeat the purpose of developing them to begin with.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The document is explanatory but also illustrates the intent of the SDT. The rationale and methods explained within the Supplementary Reference and FAQ document represent the thoughts of the SDT regarding approaches to application of the standard, but may (or may not) be of use to demonstrate compliance. FERC approves standards as mandatory and enforceable; FERC does not approve reference documents.		
MidAmerican Energy Company	Yes	The changes to the "Supplementary Reference" document appear to be acceptable, but the following are suggested as changes to enhance clarity. 1. On page 9 of the Supplementary Reference and FAQ draft the following statement is included: "Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included." On page 67, the third sentence of Section 15.3 states: "It includes [referring to control circuitry] the wiring from every trip output to every trip coil." Later in that section the following is included: "...from a protective relay that are necessary for the correct operation of the protective functions." While this later statement may be interpreted to exclude circuitry associated with relays that do not respond to non-electrical inputs or impulses it would be better to make this more explicit. It would seem illogical to require testing of circuitry that is not needed for the protective functions covered by the standard. It is suggested that a sentence like the following be added to the first paragraph of Section 15.3: "Control circuitry associated with relays that respond to non-electrical inputs or impulses is not covered by this standard and need not be tested." 2. On page 31 of the Supplementary Reference it indicates that a procedure that includes intervals less than the standard could result in a noncompliance finding even if the maximum intervals in the standard are complied with. This is contrary to previous Commission rulings on what is mandatory and enforceable (i.e. only the standard itself Ref. Order 733 p105). This FAQ response should be changed to reflect those rulings.
Response: Thank you for your comment. **1. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is**		

Organization	Yes or No	Question 5 Comment
consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff. 2. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Ameren	Yes	1. Although the explanation of 'Restore' is enlightening on page 12, 'Restore' no longer appears in the PS Maintenance definition in the last few drafts. 2. We disagree with the added burden of retaining maintenance records for removed or replaced equipment. This will actually reduce reliability because of the confusion it can cause as to what equipment is providing BES protection. At most, only the last maintenance date of the removed or replaced component should be retained if there's really a need to prove that the interval was met regarding the BES protection. 3) Remove 'Reverse power relays' from the list on page 32. They provide thermal of the steam turbine, not electrical protection of the generator.
Response: 1. Thank you for your suggestion; the SDT has revised the Supplementary Reference and FAQ document to remove the "restore" reference from the definition. 2. The records for removed/replaced equipment need to be retained to provide documentation that you were in compliance for the entire compliance monitoring period. 3. The SDT agrees that for many steam units, reverse power relays provide alarm only of a condition which could result in eventual overheating of steam turbine components. However, for many combustion turbine generators, a reverse power condition can lead to imminent failure of teeth on the speed reduction gear and thus, reverse power relays on combustion turbine generators are frequently wired as a direct trip to the generator breaker to immediately remove the motoring condition. Furthermore, in the Supplementary Reference and FAQ document, the preface to the list of relays to which you refer is as follows: "Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay may include but are not		

NERC

Organization	Yes or No	Question 5 Comment
necessarily limited to:". The SDT was attempting to provide a list of possible relays that might need to be included. The list is not meant to be all inclusive nor do all relays of the types on the list necessarily need to be included in an entity's PSMP.		
Tacoma Power	Yes	It is not clear to what extent can an entity (or auditor) can rely on information contained within the Supplementary Reference to support their position during an audit. There is a disclaimer at the beginning of the Supplementary Reference stating that "this supplementary reference to PRC-005-2 is neither mandatory nor enforceable." It seems that interpretation of the draft standard depends heavily upon this Supplementary Reference. At the same time, the Supplementary Reference does not rise to the level of a standard.
Response: Thank you for your comment. The document is explanatory but also illustrates the intent of the SDT. The rationale and methods explained within the Supplementary Reference and FAQ document represent the thoughts of the SDT regarding approaches to application of the standard, but may (or may not) be of use to demonstrate compliance. FERC approves standards as mandatory and enforceable; FERC does not approve reference documents.		
Bonneville Power Administration	Yes	
Dominion	Yes	
Entergy Services	Yes	
Independent Electricity System Operator	Yes	
City of Austin dba Austin Energy	Yes	

Organization	Yes or No	Question 5 Comment
ITC Holdings	Yes	
Dominion	Yes	
Southwest Power Pool Standards Review Group	Yes	
Pepco Holdings Inc & Affiliates	Yes	
Independent Electricity System Operator	Yes	
Northeast Utilities	Yes	
Westar Energy	Yes	
Progress Energy	Yes	
PacifiCorp	Yes	
Saft America, Inc.	Yes	
Exelon	Yes	

Organization	Yes or No	Question 5 Comment
Central Lincoln	Yes	
Dynegy Inc.	Yes	
Baltimore Gas & Electric Company	Negative Ballot	BGE's negative ballot is based on our response to Q5: While we do not disagree with the revisions to the Supplemental Reference, there remains an important item to correct. The supplementary reference on page 31, under the question beginning "Our maintenance plan calls…" states that an entity is "out of compliance" if maintenance occurs at a time longer than that specified in the entity's plan, even if that maintenance occurred at less than the maximum interval in PRC-005-2. But then on page 35-36, under the question, "How do I achieve a grace period without being out of compliance?" the response provides a presumably compliant example of scheduling maintenance at four year intervals in order to manage scheduling complexities and assure completion in less than the maximum time of six calendar years. This advice conflicts with the previous guidance. The FAQ /supplementary reference should be revised so that it does not imply that an entity is out of compliance by performing maintenance more frequently than required than the bright-line maxima in the tables. Entities may opt to test more frequently than dictated in the tables for a variety of reasons that may or may not be related to reliable protection system performance – compliance management, scheduling, operational preference, etc.
Response: The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
AEP	Negative Ballot	This negative vote is driven primarily by the concerns AEP has regarding the proposed supplementary reference documentation. If an entity adopts a more stringent maintenance program but fails to meet it, that entity could be found non-compliant despite continuing to abide by the minimum requirements of the standard itself. Entities should have the ability, if they so choose, to include additional maintenance activities or more stringent intervals than specified

Organization	Yes or No	Question 5 Comment
		within the standard without concern of penalty in the event they are unable to accomplish them. In addition, AEP is concerned by the volume of information provided in the supplementation documentation, and is uncertain how much weight that documentation might carry during audits. Note: Additional comments are being submitted via electronic form by Thad Ness on behalf of American Electric Power.
Response: Thank you for your comments. **The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.** **The document is explanatory but also illustrates the intent of the SDT. The rationale and methods explained within the Supplementary Reference and FAQ document represent the thoughts of the SDT regarding approaches to application of the standard, but may (or may not) be of use to demonstrate compliance. FERC approves standards as mandatory and enforceable; FERC does not approve reference documents.**		
Manitoba Hydro	Negative Ballot	Maintenance Activities Exceeding NERC Requirements In both the industry webinar discussion and the supplementary reference document, it was indicated that if an entity had more maintenance activities in its plan than the minimum required by PRC-005-2, then an entity would be audited to the "higher standard". We understand that an entity could write some flexibility in its program, as long as the NERC minimums were met. We are concerned that auditing to the "higher standard" could discourage entities from performing maintenance tasks beyond the NERC minimum criteria.
Response: Thank you for your comments. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
PJM Interconnection,	Negative	PJM remains concerned with a position taken by the SDT related to statements found within their Supplementary Reference & FAQ as well as the manner in which Requirement R3 has been

Organization	Yes or No	Question 5 Comment
L.L.C.	Ballot Negative Poll	drafted. The SDT's position sends industry the wrong message; a message that entities should not go beyond what is in the text of the standards and that in some cases they can even be found non-compliant by merely failing to meet their own more stringent internal practice. Therefore, PJM is voting NEGATIVE at this time. The NERC reliability standards aim to ensure an Adequate Level of Reliability (ALR). If NERC's reliability standard establishes that an ALR is achieved by a maximum allowable relay maintenance period of every 6 years in a time-based Protection System Maintenance Program (PSMP), then an entity striving to complete its maintenance every 4 years should not be found non-compliant for completing it in 5 years. We have heard NERC say in CAN Webinars and NERC Workshops that "auditors must audit to the standard", however, the position taken by the SDT within their Supplementary Reference and FAQ document and the wording of Requirement R3 is contrary to this position.
Response: Thank you for your comments. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
FirstEnergy	No	We do not agree with aspects of the Supplementary Reference document as discussed in Question 6.
Response: Thank you for your comments. Please see our response to your comments in Question 6.		
NERC Staff Technical Review	No	We recommend changes to Supplementary Reference. It appears the 3 calendar month interval referenced in the second FAQ in section 7.1 on page 20, Example 1 on page 21, Example 2 on page 22, and on page 23 should be updated to 4 calendar months consistent with the changes to the standard for verification of station dc supply voltage and inspection of electrolyte level and unintentional grounds. We recommend modifying references to UFLS and UVLS to clarify the intervals for distributed systems applies to both UFLS and UVLS similar to the recommended change to the standard in our comment on question 4. See pp. 26, 30, 33, 86, and 87 of the supplementary reference.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. **1. Thank you for comment; the Supplementary Reference and FAQ document has been changed.** **2. Changes have been made to the standard and its Supplementary Reference and FAQ document.**		
MRO's NERC Standards Review Forum	No	a. Page 9, "Is a Sudden Pressure Relay an auxiliary tripping relay? "1) During the webinar on Thursday, September 15th it was asked whether the trip path for a sudden pressure relay needed to be confirmed. Based on this question, we believe that the FAQ should be modified as follows:i. Is a Sudden Pressure Relay an auxiliary tripping relay? No. IEEE C37.2-2008 assigns the device number 94 to auxiliary tripping relays. Sudden pressure relays are assigned device number 63. Sudden pressure relays are excluded from the Standard because it does not utilize voltage and/or current measurements to determine anomalies. Since the sudden pressure relay is not included, it also follows that trip path testing for this relay type is also excluded. b. On page 26 of the Supplementary Reference document, it states, "If your PSMP (plan) requires more activities than you must perform and document to this higher standard." This penalizes utilities from including best practices in their PSMP, and encourages utilities to implement the standard maintenance practice instead of a higher maintenance practice. Why would a utility accept the additional risk of a NERC penalty or sanction when they can stay in compliance by accepting the minimum requirements of the standard? By stating this, the PSMP will include only those required items at the minimum frequency to avoid a compliance violation. For the reliability of the BES, recommend the wording be changed to, "If your PSMP (plan) requires more activities than required by PRC-005-2, you will be held accountable only to the minimum requirements in the standard. NERC encourages utilities to implement best practices to improve the reliability of the BES, so utilities will not be penalized for exceeding the standards." In FERC Order 693, section 278 FERC states: While we appreciate that many entities may perform at a higher level than that required by the Reliability Standards, and commend them for doing so, the Commission is focused on what is required under the Reliability Standards, we do not require that they exceed the Reliability Standards". c. Page 78, last paragraph: If the same type of ohmic testing is done (impedance, conductance or

Organization	Yes or No	Question 5 Comment
		resistance), may a different manufacturer's test equipment be used for this testing? d. Page 79, second paragraph of "Why verify voltage?": 1) "The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning." i. Is it the intent of the PSMT SDT that this measurement is taken at the battery terminals, or will a reading taken from the battery charger panel meter meet this requirement? 2) "The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits." i. Is it the intent of the PSMT SDT that this measurement is taken at the battery terminals, or will a reading taken from the battery charger panel meter meet this requirement? e. Except as noted above, the changes to the "Supplementary Reference" document appear to be acceptable, but the following are suggested as changes to enhance clarity. 1) On page 9 of the Supplementary Reference and FAQ draft the following statement is included: "Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included." On page 67, the third sentence of Section 15.3 states: "It includes [referring to control circuitry] the wiring from every trip output to every trip coil." Later in that section the following is included: "...from a protective relay that are necessary for the correct operation of the protective functions." While this later statement may be interpreted to exclude circuitry associated with relays that do not respond to non-electrical inputs or impulses it would be better to make this more explicit. It would seem illogical to require testing of circuitry that is not needed for the protective functions covered by the standard. It is suggested that a sentence like the following be added to the first paragraph of Section 15.3: "Control circuitry associated with relays that respond to non-electrical inputs or impulses is not covered by this standard and need not be tested." 2) On page 31 of the Supplementary Reference it indicates that a procedure that includes intervals less than the standard could result in a noncompliance finding even if the maximum

Organization	Yes or No	Question 5 Comment
		intervals in the standard are complied with. This is contrary to previous Commission rulings on what is mandatory and enforceable (i.e. only the standard itself Ref. Order 733 p105). This FAQ response should be changed to reflect those rulings.
Response: Thank you for your comment. **1. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff.** **2. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.** **3. Yes. Your concern, of course should be that your results can be trended from test to test. The Supplementary Reference and FAQ document has been changed.** **4. The Supplementary Reference and FAQ document has been changed to add clarity.** **5. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff. As to part 2, The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, R1 part 1.3 has been removed; R3 has been revised so that, for time-based programs, entities shall comply with the tables; R4 has been added to address performance-based maintenance, and R5 has been added to address Unresolved Maintenance Issues.**		
ACES Power Collaborators	No	There are some changes that are needed to the document. 1. On Page 19, the second question refers to R1.4. There is no R1.4 in the standard. We assume

Organization	Yes or No	Question 5 Comment
		that document is intended to refer to part 1.4 under R1. This needs to be clarified and corrected. 2. The reference document creates an improper incentive to eliminate best practices and utilize the maximum time intervals established in the standard. The document states that an entity will be subject to compliance violations if it has a maintenance and testing program with time intervals that are more stringent than the maximum time intervals in the standard and it does not meet its more stringent intervals. This would hold true even if the registered entity meets the maximum intervals established in the standard. To reduce compliance risk, registered entities will be incented to increase its time intervals to the maximum allowed by the standard. This is contrary to supporting reliability. Penalizing entities for failing to meet their more stringent plan requirements is also contrary to guidance provided by the Commission. Doug Curry, General Counsel of Lincoln Electric System, spoke to the Commission at the November 18, 2010 FERC technical conference on reliability monitoring, enforcement and compliance about his company's experience with the vegetation management standard. They exceeded the requirements for annual inspections by including six aerial patrols each year but were found in violation of the standard and paid penalties when they did not complete but one aerial patrol in the first five months of the year. The auditors concluded that the company's ground patrol fully satisfied the minimum requirements of the standard. In the end, LES removed the aerial inspections from the vegetation management plan. The Commissioners acknowledged that this was contrary to their goal of an adequate level of reliability and agreed that an entity should not be penalized for failing to meet their more stringent requirements when they meet the standard requirements. 3. On Page 34, the FAQ about commissioning does not appear to be consistent with CAN-0011. While we believe the reference document is more correct, the drafting team should compare the advice given in the reference document to that in the CAN to ensure that it is not conflicting. Given that NERC is in the process of revising all of the CANs, the best approach may simply be to add a statement referencing the CAN-0011 for further information. 4. Comments about "gaming the PBM system" regarding restoring segment performance should be removed from the reference document. Comments like these indicate intent by a

Organization	Yes or No	Question 5 Comment
		registered entity to manipulate the compliance process. Only after a thorough investigation can such intent be determined. Thus, there shouldn't be a presumption that registered entities will attempt this. Better comments would be to focus on the consistency that the three year period provides in determining segment performance. 5. In section 12.1 on page 58, the reference document discusses out of service equipment. NERC recently issued a lesson learned on removing unused relaying equipment on August 10, 2011. The drafting team may wish to reference that lesson learned in the reference document.
Response: Thank you for your comment. **1. The Supplementary Reference and FAQ document has been changed.** **2. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.** **3. The Supplementary Reference and FAQ document has been changed.** **4. The Supplementary Reference and FAQ document has been changed.** **5. The Supplementary Reference and FAQ document has been changed to incorporate a discussion of the cited Lessons Learned.**		
Southern Company Generation	No	Several additional edits are needed so that the document matches the proposed standard: 1) In Section 5.1.1, page 16, add "and Table 3" in the Figure and at the end of FAQ after figure in that section. 2) In Section 7.1, example #1, a 3 month battery interval is shown 3) In Section 8.1.1, a 3 month interval is shown for communication circuit 4) In Section 15.5.1, several references to "3 month" and "three month" intervals are shown for communication circuits. 5) In Appendix B, the formatting is incorrect for Al McMeekin's company name.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comment. The Supplementary Reference and FAQ document has been changed to address each of your suggestions.		
Nebraska Public Power District	No	a. On page 26 of the Supplementary Reference document, it states, "If your PSMP (plan) requires more activities than you must perform and document to this higher standard." This penalizes utilities from including best practices in their PSMP, and encourages utilities to implement the standard maintenance practice instead of a higher maintenance practice. Why would a utility accept the additional risk of a NERC penalty or sanction when they can stay in compliance by accepting the minimum requirements of the standard? By stating this, the PSMP will include only those required items at the minimum frequency to avoid a compliance violation. For the reliability of the BES, recommend the wording be changed to, "If your PSMP (plan) requires more activities than required by PRC-005-2, you will be held accountable only to the minimum requirements in the standard. NERC encourages utilities to implement best practices to improve the reliability of the BES, so utilities will not be penalized for exceeding the standards." In FERC Order 693, section 278 FERC states: While we appreciate that many entities may perform at a higher level than that required by the Reliability Standards, and commend them for doing so, the Commission is focused on what is required under the Reliability Standards, we do not require that they exceed the Reliability Standards".
Response: The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
American Electric Power	No	With such a complex standard as this, the FAQ and Supplementary Reference documents do aid the Protection System owner in demystifying the requirements. However, AEP is uncertain how much weight the documents might carry during audits. We recommend that this additional information be included within the actual standard (for example in an appendix) but in a more compact version. Section 15.7 of the supplementary reference includes the bullet point "No verification of trip path

Organization	Yes or No	Question 5 Comment
		required between the lock-out and/or auxiliary tripping device(s).” This appears to contradict the other bullet points within Section 15.7.
Response: Thank you for your comment. **1. Doing as you suggest would make the supporting information within the Supplementary Reference and FAQ document part of the standard and this would add extensive and unnecessary prescription to the standard.** **2. The Supplementary Reference and FAQ document has been changed.**		
Lincoln Electric System	No	Please see the comments submitted by the MRO NSRF.
Response: Please see our response to the comments submitted by the MRO NSRF.		
Liberty Electric Power LLC	No	The reference contains language which makes it a violation should an entity choose a cycle time less than the maximum from the table, and then fails to meet that cycle. (See page 27, "If your PSMP (plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard.") There is no reason to hold a RE in violation if all work is performed within the maximum time from the table - either there was no reliability risk, or the table is incorrect and a reliability risk in itself.
Response: The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Manitoba Hydro	No	1. Page 26: In both the industry webinar discussion and the supplementary reference document, it was indicated that if an entity had more maintenance activities in its plan than the minimum required by PRC-005-2, then an entity would be audited to the "higher standard". We understand that an entity could write some flexibility in its program, as long as the NERC minimums were met. We are concerned that auditing to the "higher standard" could

Organization	Yes or No	Question 5 Comment
		discourage entities from performing maintenance tasks beyond the NERC minimum criteria. 2. The discussion on page 9 indicates that although the relays which respond to mechanical parameters are not included in the scope of PRC-005-2, the associated trip circuits are included. We suggest that neither the relays which respond to mechanical parameters nor their associated trip circuits are within the scope of this standard 3. References to the tables should be consistently updated to include the new Table 3. “Every 3 calendar months” should be updated throughout the document to “Every 4 calendar months”. For example, Page 23: Example #3 should be revised. 4. In addition, there are a number of grammatical errors in the document, particularly capitalization and punctuation, which make it difficult to read. There are terms which are improperly capitalized implying that they are approved NERC Glossary of Terms definitions when they are not.
Response Thank you for your comment. **1. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.** **2. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff.** **3. The Supplementary Reference and FAQ document has been changed.** **4. The Supplementary Reference and FAQ document has had identified errors corrected.**		
American Transmission	No	ATC provides the following suggestions for change:

Organization	Yes or No	Question 5 Comment
Company		1. Page 9, "Is a Sudden Pressure Relay an auxiliary tripping relay? "During the webinar on Thursday, September 15th it was asked whether the trip path for a sudden pressure relay needed to be confirmed. Based on this question, we believe that the FAQ should be modified as follows: Is a Sudden Pressure Relay an auxiliary tripping relay?No. IEEE C37.2-2008 assigns the device number 94 to auxiliary tripping relays. Sudden pressure relays are assigned device number 63. Sudden pressure relays are excluded from the Standard because it does not utilize voltage and/or current measurements to determine anomalies. Since the sudden pressure relay is not included, it also follows that trip path testing for this relay type is also excluded. 2. Page 78, last paragraph:If the same type of ohmic testing is done (impedance, conductance or resistance), modify the FAQ to allow the use of a different manufacturer's test equipment to conduct the testing. 3. Page 80, second paragraph: "The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning." Insert the following: "A reading taken from the battery charger panel meter will meet this requirement." "The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits." Insert the following." A reading taken from the battery charger panel meter will meet this requirement."

Response: Thank you for your comments.

1. **The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff.**
2. **In the Supplementary Reference and FAQ document, the SDT is discussing methods of performing ohmic testing but is not specifying any particular test or test equipment.**
3. **The Supplementary Reference and FAQ document has been changed.**

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td>Southern Company Transmission</td><td>No</td><td>1. Page 16: ‘Add and Table 3’ in Figure and end of FAQ after figure
2. Page 20: change reference from 3 to 4 months. This applies throughout document.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The Supplementary Reference and FAQ document has been changed.
2. The Supplementary Reference and FAQ document has been changed.</td></tr>
<tr><td>CenterPoint Energy</td><td>No</td><td>CenterPoint Energy appreciates that there is now only one document, instead of the two originally proposed. However, we question the name of the document which shows “Supplemental Reference and FAQ”. The use of “Supplemental Reference” could infer it contains requirements not found in the PRC-005-2 standard. Also, we suggest that NERC standardize on the names of documents associated with standards and other NERC initiatives. CenterPoint Energy recommends the name of the document be “Technical Reference”.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment. The Supplementary Reference and FAQ document is explanatory in nature.</td></tr>
<tr><td>BGE</td><td>No</td><td>While we do not disagree with the revisions to the Supplemental Reference, there remains an important item to correct. The supplementary reference on page 31, under the question beginning “Our maintenance plan calls...” states that an entity is “out of compliance” if maintenance occurs at a time longer than that specified in the entity’s plan, even if that maintenance occurred at less than the maximum interval in PRC-005-2. But then on page 35-36, under the question, “How do I achieve a grace period without being out of compliance?” the response provides a presumably compliant example of scheduling maintenance at four year intervals in order to manage scheduling complexities and assure completion in less than the maximum time of six calendar years. This advice conflicts with the previous guidance. The FAQ /supplementary reference should be revised so that it does not imply that an entity is out-of-compliance by performing maintenance more frequently than required than the bright-line maxima in the tables. Entities may opt to test more frequently than dictated in the tables for a variety of reasons that may or may not be related to reliable protection system performance - compliance management, scheduling, operational</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		preference, etc.
Response: The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Constellation Power Generation	No	While we do not disagree with the revisions to the Supplemental Reference, there remains an important item to correct. The supplementary reference on page 31, under the question beginning “Our maintenance plan calls...” states that an entity is “out of compliance” if maintenance occurs at a time longer than that specified in the entity’s plan, even if that maintenance occurred at less than the maximum interval in PRC-005-2. But then on page 35-36, under the question, “How do I achieve a grace period without being out of compliance?” the response provides a presumably compliant example of scheduling maintenance at four year intervals in order to manage scheduling complexities and assure completion in less than the maximum time of six calendar years. This advice conflicts with the previous guidance. The FAQ /supplementary reference should be revised so that it does not imply that an entity is out-of-compliance by performing maintenance more frequently than required than the bright-line maxima in the tables. Entities may opt to test more frequently than dictated in the tables for a variety of reasons that may or may not be related to reliable protection system performance - compliance management, scheduling, operational preference, etc. The discussion of “grace period” may be best clarified as a term to include in an entity’s PSMP that grants entities the flexibility to maintain compliance if testing occurs between an entity’s plan interval and the bright-line interval.
Response: The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Constellation Energy	No	While we do not disagree with the revisions to the Supplemental Reference, there remains an important item to correct. The supplementary reference on page 31, under the question beginning

Organization	Yes or No	Question 5 Comment
Commodities Group		"Our maintenance plan calls..." states that an entity is "out of compliance" if maintenance occurs at a time longer than that specified in the entity's plan, even if that maintenance occurred at less than the maximum interval in PRC-005-2. But then on page 35-36, under the question, "How do I achieve a grace period without being out of compliance?" the response provides a presumably compliant example of scheduling maintenance at four year intervals in order to manage scheduling complexities and assure completion in less than the maximum time of six calendar years. This advice conflicts with the previous guidance. The FAQ /supplementary reference should be revised so that it does not imply that an entity is out-of-compliance by performing maintenance more frequently than required than the bright-line maxima in the tables. Entities may opt to test more frequently than dictated in the tables for a variety of reasons that may or may not be related to reliable protection system performance - compliance management, scheduling, operational preference, etc. The discussion of "grace period" may be best clarified as a term to include in an entity's PSMP that grants entities the flexibility to maintain compliance if testing occurs between an entity's plan interval and the bright-line interval.
Response: The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Western Area Power Administration	No	See comments under question 6
Response: Please see our response to your comments in Question 6.		
Tennessee Valley Authority	No	

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

Summary Consideration:

Many commenters objected to Requirement R3 and to the explanation that entities would be held to compliance on "either the Tables or their PSMP, whichever is more stringent". In response to these comments, the SDT modified the standard to remove Requirement R1 part 1.3, and revised Requirement R3 so that, for time-based programs, entities shall comply with the Tables rather than their PSMP. The SDT added Requirement R4 to address performance-based maintenance, and added Requirement R5 to address Unresolved Maintenance Issues. The Supplementary Reference and FAQ document was updated to reflect these changes.

Several commenters questioned the inclusion of the dc control circuitry for sudden pressure relays even though the relays themselves are excluded from the definition of "Protection System"; the SDT reiterated its position that this dc control circuitry is indeed included because the dc control circuitry is associated with protective functions.

Several comments were offered objecting that the VSLs establish that any non-compliance is a violation, and that "perfection is unrealistic". The SDT responded that the VSL Guidelines do not provide for an entity to be out of performance to some degree without incurring a violation.

Several comments were offered regarding "Unresolved Maintenance Issues". Some of these comments suggested that the entity should be required to resolve such issues, rather than initiating resolution. Others offered concerns regarding the definition of this term itself or the related VSLs. The SDT revised the definition to: "A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, and requires follow-up corrective action." The VSLs for the old Requirement R3 (new Requirement R5) were revised from graduated "%" to graduated "hard counts" of violations. The SDT also clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues.

Other comments were offered regarding Data Retention, generally objecting to retaining the maintenance records for two full intervals. The SDT explained that this expectation is consistent with the Compliance Monitoring and Enforcement Program.

Several commenters questioned the verification of lockout and auxiliary relays every 6 years. The SDT explained their rationale for this requirement relative to lockout relays, and did move the auxiliary relays to the 12-year control circuitry verification.

Several comments were offered on the Implementation plan, resulting in several clarifying changes.

Many comments were offered, questioning the Applicability of the standard relative to the recently-approved Interpretation of "transmission Protection System". The SDT explained that PRC-005-2 does not use this term; thus the interpretation does not apply. The SDT also explained that the Applicability in PRC-005 is correct and that it supports the reliability of the BES.

In response to comments, the SDT revised Applicability 4.2.5.4 to indicate that, for generator-connected station service transformers, only the Protection Systems that trip the generator, either directly or via a lockout relay are included in the standard.

In response to comments, Table 1-4(f) was modified to more accurately represent the monitoring attributes and related activities for monitored Vented Lead-Acid and Valve-Regulated Lead-Acid batteries.

Organization	Yes or No	Question 6 Comment
City of Austin dba Austin Energy	Affirmative Ballot	(1) The following language should be clarified to make it clear that a Registered Entity does not have to include its detailed maintenance procedures in its PSMP: 1.4. Include all applicable monitoring attributes and related maintenance activities applied to each Protection System component type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3.
	Affirmative Poll	(2) For a modern digital relay panel, designed with monitored components and electromechanical lockouts, the maintenance interval would otherwise be a maximum of 12 years except that the lockout must be electrically operated every 6 years. We cannot see justification for a separate maintenance activity to just test the lockouts, due to the increased human error associated with testing lockouts and the low likelihood of a lockout failure. We recommend that the lockouts be tested on a 12 year basis, perhaps in association with the "Unmonitored control circuitry associated with protective functions" as found in Table 1-5. By doing so, we feel that the risk of an undesired operation due to human error can be minimized and not degrade system reliability.
		(3) If sudden pressure relays are exempt from the Standard, the DC circuitry for those relays should also be exempt.
		(4) If a Registered Entity has a PSMP that is more stringent than the intervals in PRC-005-2, the Registered Entity should not be considered out of compliance if it fails to meet its internal interval but remains within the interval set forth in PRC-005-2.

Response: Thank you for your comments.

1. The SDT's intent with the R1.4 wording is to convey that the entity's PSMP must document that the monitoring attributes of any given component type meet the Table-specified monitoring attributes in order to justify exclusion of the maintenance activities and/or the lengthening of maintenance intervals as provided for in the Tables. PRC-005-2 does not have requirements for inclusion of detailed maintenance procedures in an entity's PSMP as the tables within the standard have taken the place of the "summary of maintenance and testing procedures" required by R1.2 of PRC-005-1.
2. The SDT believes that electromechanical lockout relays need periodic operation in order to remain reliable. As such, these devices are required to be exercised at the same 6 year interval required for electromechanical relays. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed. Performance-based maintenance is an option if you want to extend your intervals beyond 6 years. The SDT, however, has modified Table 1-5 to remove other auxiliary relays, etc, from this activity, and clarified that the verification of such devices is included within the 12-year unmonitored control circuitry verification.
3. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff.
4. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.

City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power	Affirmative Ballot	1. The implementation plan for R2 and R3 is unclear on whether each maintenance activity has its own implementation schedule. The implementation plan can also be interpreted to mean that the implementation schedule for a given protection system component is driven by the smallest maximum maintenance (allowable) interval. For example, for unmonitored communications systems, it is unclear whether all maintenance activities indicated in Table 1-2, including those corresponding to 6 calendar years, must be completed on all unmonitored communications systems by the first calendar quarter 15 months following applicable regulatory approval, or if this timeline only applies to the maintenance activity specified in Table 1-2 corresponding to a maximum maintenance interval of 4 calendar months.
		2. Assuming that there is a different implementation schedule for different maintenance activities for some protection system component types (namely station DC supply and communication systems), the middle bullet on page 1 of the implementation plan does not seem to consider that it may not be possible to identify whether some protection system components are completely being addressed by PRC-005-2 or the Program developed for the previous standards. In other words, during implementation, some maintenance activities for the same protection system component may be addressed by PRC-005-2, while other maintenance activities may be addressed by the Program developed for the previous standards.
		3. It is unclear whether control circuitry (trip paths) from protective relays that respond to mechanical quantities is included. This issue is addressed in the supplementary reference but is vague in the draft standard itself.
		4. This draft of PRC-005-2 requires the Protection System Maintenance Program (PSMP) to “include all applicable monitoring attributes and related maintenance activities” per the Tables and requires an entity to “implement and follow its PSMP.” Under the draft standard, it is unclear whether an entity has to document in the PSMP and/or maintenance records how they accomplish(ed) the maintenance activities or simply to indicate that the maintenance activities are included and have been completed within the defined intervals. It is clear that entities are afforded some latitude in how they conduct the required maintenance activities. However, the level of detail required to document (1) how an entity chooses to perform the maintenance activities and (2) that applicable maintenance activities have been completed is not clear.

		5. In Table 1-2, there is a maintenance activity related to communication systems to "verify essential signals to and from other Protection System components." It is unclear if this statement is referring to control circuitry associated with the communication system end devices, end device input and output operation (as in Table 1-1 for protective relays), or something else. It is recommended that the requirement be to "verify operation of communication system inputs and outputs that are essential to proper functioning of the Protection System." This language is consistent with that used for protective relays in Table 1-1.
		6. Referring to Table 1-2, it is unclear whether an entity has the sole authority decide which 'performance criteria' are 'pertinent.' Additionally, it is unclear if an entity must document the 'communications technology applied' and the associated 'performance criteria' in its PSMP.
		7. In Table 1-4, it is unclear if there is a distinction between the terms 'resistance' and 'ohmic values.' If there is a distinction, then this distinction should be clarified.
		8. In Table 1-4, it is unclear if there is a distinction between the terms 'battery terminal connection resistance' and 'unit-to-unit connection resistance.' If there is a distinction, then this distinction should be clarified.
		9. In Table 1-4, replace the term 'resistance' with 'impedance.'
		10. Recommend that the 6 calendar month interval in Table 1-4(b) be lengthened to 18 calendar months to be more consistent with similar maintenance activities for other battery types. At minimum, lengthen the interval to at least 7 calendar months in a similar way that 3 calendar months was lengthened to 4 calendar months for other maintenance activities.

		11. Referring to Table 1-5, no periodic maintenance is required for “control circuitry whose continuity and energization or ability to operate are monitored and alarmed.” It is unclear whether or not it is acceptable to verify DC voltage at the actuating device trip terminals at least once every 12 calendar years for “unmonitored control circuitry associated with protective functions.” It is recommended that periodically verifying DC voltage in this manner be an acceptable means of accomplishing the maintenance activity identified in Table 1-5 for unmonitored control circuitry associated with protective functions.
		12. Referring to 4.2. Facilities of the draft standard, it is unclear whether protection systems for transformers that step down from over 100kV to below 15kV are applicable to the standard. Even if there are normally-open distribution feeder ties for purposes of transferring load in a make-before-break fashion, these transformers are generally not considered BES elements.
		13. Referring to 4.2.5 of the draft standard, it is unclear whether protection for generator excitation systems are applicable to the standard.
		14. It is unclear whether external timing relays (e.g., Zone 2) are considered control circuitry components (like lockout and auxiliary relays) or protective relay components.

Response:	**Thank you for your comments.**
	1. The SDT agrees with your observation and has changed the relevant parts of the implementation plan to clarify that they apply to the maintenance activities for the relevant maintenance intervals.
	2. The SDT agrees with your observation and has revised the Implementation plan to clarify.

	3. The trip paths from protective relays that respond to mechanical quantities and are intended to detect faults are a part of the Protection System control circuitry. The sensing elements are omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocols for these sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff. Note that trip signals from devices sensing mechanical parameters not directly indicative of an electrical fault need not be tested per this standard.
	4. The SDT has removed parts 1.1 and 1.3 from Requirement R1, addressing part of your comment. The SDT agrees that PRC-005-2 allows some leeway in how an entity fulfills the testing requirements of the standard. Section 15 of the Supplementary Reference and FAQ document provides numerous examples of possible testing techniques for the various component types making up a Protection System. An entity's PSMP should clearly define how the testing requirements of the standard are fulfilled. The Measures for each requirement, as well as Section 15.8 of the Supplementary Reference and FAQ document, provide some examples of possible compliance documentation for completion of testing.
	5. The SDT agrees with your suggestion and has changed the standard accordingly.
	6. The entity has the authority to establish its own acceptable performance criteria. This criteria does not need to be in the PSMP, but should reside somewhere within the maintenance documentation.
	7. As utilized on Table 1-4, the term "ohmic value" is a generic reference to the measurement of a battery cell or units ability to pass current flow. This may be done using conductance, resistance or impedance measurements; the various battery test equipment manufacturers use different measurement methods and the term "ohmic value" is meant to be technology neutral. See FAQ on page 78 of the Supplementary Reference and FAQ document. The term "resistance" as used in Table 1-4 refers specifically to the dc resistance of the battery terminal connections and the battery intercell/inter-unit physical connectors. See related FAQ on pages 74-75 of the Supplementary Reference and FAQ document.

	8. Battery terminal connection resistance is a measurement of the resistance of a connection at a battery terminal. Battery intercell or unit-to-unit connection resistance is a measurement of the resistance of the external conductor interconnecting two adjacent battery cells or two adjacent multi-cell battery units. The SDT believes these are common battery maintenance terms used throughout the industry.
	9. The SDT disagrees and believes that resistance as used in Table 1-4 is the appropriate term for the parameters to be measured and is consistent with standard battery system maintenance terminology.
	10. The SDT disagrees with your recommendation to standardize maintenance intervals between different battery types that have distinctly different failure mechanisms. See related FAQ on pages 80-81 of the Supplementary Reference and FAQ document for further discussion of requirements for ohmic measurements of VRLA batteries. Concerning your recommendation to allow for 7 calendar months, the SDT believes that the six-month interval specified is appropriate.
	11. The SDT has modified this specific portion of the Table, and believes that the modifications address your concern. Please see Section 15.3 of the Supplementary Reference and FAQ document for a discussion of this topic.
	12. The standard does not include the Protection Systems for transformers that step down from over 100kV to below 15kV if these transformers are not BES elements. If Protection Systems are installed for purposes of detecting Faults on BES elements, these Protection Systems are included.
	13. Paragraph 4.2.5.1 indicates that the excitation system protection system would only be in scope if the excitation system generates signals that trip the generator output breaker either directly or via lockout or auxiliary tripping relays.
	14. As timing is critical to proper Protection System function, timers are considered protective relays.

Ameren Services	Affirmative Ballot	Measure M3 on page 5 should only apply to 99.5% of the components. Please revise to state: “Each … shall have evidence that it has implemented the Protection System Maintenance Program for 99.5% of its components and initiated….” PRC-005-2 unrealistically mandates perfection without providing technical justification. A basic premise of engineering is to allow for reasonable tolerances, even Six Sigma allows for defects. Requiring perfection may well harm reliability by distracting valuable resources from higher priority duties concerning the Protection System. We are not asking for the VSL to be changed. No one is perfect and it is impractical to imply perfection is achievable. The consequence of a very small number of components having a missed or late maintenance activity is insignificant to BES reliability. Our proposed reasonable tolerance sets an appropriate level of performance expectation. We disagree with the notion that this is “non-performance”. An alternate approach regarding the unrealistic perfection of M3 is to correctly recognize that the protection of the primary BES is the objective. Most Protection Systems are redundant by design and the entity needs to be afforded the opportunity to show that a redundant component met the PSMP thereby providing the required protection. The entity should be allowed a reasonable time frame of one calendar increment to maintain the component in question. Our concern stems from the tens of thousands of components in a PSMP, and the reality that rarely but occasionally a data base error or outage scheduling issue may result in a very small number component exceeding their maximum interval. As long as the entity can show that BES protection was sustained and maintains the component quickly (e.g. within one calendar month of discovery), BES reliability has been maintained.
Response: Thank you for comment. **The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. The graded approach of the VSL for Requirement R3 allows the RRO to provide discretion when assessing severity of the violation when only a relatively small number of maintenance activities have been missed.**		

City of Austin dba Austin Energy	Affirmative Ballot	1. The following language should be clarified to make it clear that a Registered Entity does not have to include its detailed maintenance procedures in its PSMP: "all applicable monitoring attributes and related maintenance activities ". Reference: R1.4. Include all applicable monitoring attributes and related maintenance activities applied to each Protection System component type consistent with the maintenance intervals specified in Tables 1-1 through 1-5, Table 2, and Table 3. 2. For a modern digital relay panel, designed with monitored components and electromechanical lockouts, the maintenance interval would otherwise be a maximum of 12 years except that the lockout must be electrically operated every 6 years. We cannot see justification for a separate maintenance activity to just test the lockouts, due to the increased human error associated with testing lockouts and the low likelihood of a lockout failure. We recommend that the lockouts be tested on a 12 year basis, perhaps in association with the “Unmonitored control circuitry associated with protective functions” as found in Table 1-5. By doing so, we feel that the risk of an undesired operation due to human error can be minimized and not degrade system reliability. 3. If sudden pressure relays are exempt from the Standard, the DC circuitry for those relays should also be exempt.

Response: Thank you for your comments.

1. **The SDT’s intent with the Requirement R1.4 (new Requirement R1.2) wording is to convey that the entity’s PSMP must document that the monitoring attributes of any given component type meet the Table-specified monitoring attributes in order to justify exclusion of the maintenance activities and/or the lengthening of maintenance intervals as provided for in the Tables. PRC-005-2 does not have requirements for inclusion of detailed maintenance procedures in an entity’s PSMP as the tables within the standard have taken the place of the “summary of maintenance and testing procedures” required by R1.2 of PRC-005-1.**
2. **The SDT believes that electromechanical lockout relays need periodic operation in order to remain reliable. As such, these devices are required to be exercised at the same 6 year interval required for electromechanical relays. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed. Performance-based maintenance is an option if you want to extend your intervals beyond 6 years. The SDT, however, has modified Table 1-5 to remove other auxiliary relays, etc, from this activity, and clarified that the verification of such devices is included within the 12-year unmonitored control circuitry verification.**
3. **The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is**

omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff.		
International Transmission Company Holdings Corp	Affirmative Ballot	While voting "Affirmative" on this ballot, ITC continues to have concerns with testing intervals. These comments have been submitted via the Comment Form associated with this project.
Response: Thank you for your affirmative vote. Please see our responses to our comments elsewhere in this report.		
Occidental Chemical	Affirmative Ballot	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. Ingleside Cogeneration, LP, continues to believe that the six year requirement to verify channel performance on associated communications equipment will prove to be more detrimental than beneficial on older relays. Clearly newer technology relays which provide read-outs of signal level or data-error rates will easily verified, but the tools which measure power levels and error rates on non-monitored communication links are far more intrusive. After the technician uncouples and re-attaches a fiber optic connection, the communications channel may be left in worse shape after verification than it was prior to the start of the test.
Response: Thank you for your comment and affirmative vote. **There are less intrusive ways to verify channel performance that do not require disconnecting communication terminations. It is up to the entity to determine specific maintenance techniques.**		

Oncor Electric Delivery	Affirmative Ballot	PRC-005-2 is a vast improvement over the vagueness of the existing standard (PRC-005-1), that the new standard makes compliance much easier than the present standard. The new standard recognizes the advances in relay technology and reliability, particularly the benefits of microprocessor based relays. The standard also provides greater flexibility on its implementation while recognizing the benefits of a performance based methodology, particularly as it relates to battery testing. The revised standard eliminates the requirement for a "summary of maintenance and testing procedures" which was vague and provided no real value to the registered entities. Operational and administrative efficiencies can be realized by consolidating the relay testing and maintenance requirements into one standard (PRC-005-1, PRC-008-0, PRC-011-0, PRC-017-0)
Response: Thank you for your comment and affirmative vote.		
Public Utility District No. 2 of Grant County	Affirmative Ballot	We are ok with this standard, however, we would like to see some recognition of the use of non-calendar based maintenance practices such as predictive maintenance practices or condition based maintenance practices. When you use one of those methodologies for the basis for your plant maintenance it is very labor intensive to interpret those results to a calendar based requirement.
Response: Thank you for your comment and affirmative vote. **Please see Sections 5, 6, and 7 of the Supplementary Reference and FAQ for a discussion of how the SDT has attempted to incorporate condition-based maintenance practices (utilizing installed monitoring capabilities) and performance-based maintenance practices within PRC-005-2.**		
Tacoma Public Utilities	Affirmative Ballot	1. The implementation plan for R2 and R3 is unclear on whether each maintenance activity has its own implementation schedule. The implementation plan can also be interpreted to mean that the implementation schedule for a given protection system component is driven by the smallest maximum maintenance (allowable) interval. For example, for unmonitored communications systems, it is unclear whether all maintenance activities indicated in Table 1-2, including those corresponding to 6 calendar years, must be completed on all unmonitored communications systems by the first calendar quarter 15 months following applicable regulatory approval, or if this timeline only applies to the maintenance activity specified in Table 1-2 corresponding to a maximum maintenance interval of 4 calendar months.

		2. Assuming that there is a different implementation schedule for different maintenance activities for some protection system component types (namely station dc supply and communication systems), the middle bullet on page 1 of the implementation plan does not seem to consider that it may not be possible to identify whether some protection system components are completely being addressed by PRC-005-2 or the Program developed for the previous standards. In other words, during implementation, some maintenance activities for the same protection system component may be addressed by PRC-005-2, while other maintenance activities may be addressed by the Program develoepd for the previous standards.
		3. It is unclear whether control circuitry (trip paths) from protective relays that respond to mechanical quantities is included. This issue is addressed in the supplementary reference but is vague in the draft standard itself.
		4. This draft of PRC-005-2 requires the Protection System Maintenance Program (PSMP) to “include all applicable monitoring attributes and related maintenance activities” per the Tables and requires an entity to “implement and follow its PSMP.” Under the draft standard, it is unclear whether an entity has to document in the PSMP and/or maintenance records how they accomplish(ed) the maintenance activities or simply to indicate that the maintenance activities are included and have been completed within the defined intervals. It is clear that entities are afforded some latitude in how they conduct the required maintenance activities. However, the level of detail required to document (1) how an entity chooses to perform the maintenance activities and (2) that applicable maintenance activities have been completed is not clear.
		5. In Table 1-2, there is a maintenance activity related to communication systems to “verify essential signals to and from other Protection System components.” It is unclear if this statement is referring to control circuitry associated with the communication system end devices, end device input and output operation (as in Table 1-1 for protective relays), or something else. It is recommended that the requirement be to “verify operation of communication system inputs and outputs that are essential to proper functioning of the Protection System.” This language is consistent with that used for protective relays in Table 1-1.

		6. Referring to Table 1-2, it is unclear whether an entity has the sole authority decide which ‘performance criteria’ are ‘pertinent.’ Additionally, it is unclear if an entity must document the ‘communications technology applied’ and the associated ‘performance criteria’ in its PSMP.
		7. In Table 1-4, it is unclear if there is a distinction between the terms ‘resistance’ and ‘ohmic values.’ If there is a distinction, then this distinction should be clarified.
		8. In Table 1-4, it is unclear if there is a distinction between the terms ‘battery terminal connection resistance’ and ‘unit-to-unit connection resistance.’ If there is a distinction, then this distinction should be clarified.
		9. In Table 1-4, replace the term ‘resistance’ with ‘impedance.’
		10. Recommend that the 6 calendar month interval in Table 1-4(b) be lengthened to 18 calendar months to be more consistent with similar maintenance activities for other battery types. At minimum, lengthen the interval to at least 7 calendar months in a similar way that 3 calendar months was lengthened to 4 calendar months for other maintenance activities.
		11. Referring to Table 1-5, no periodic maintenance is required for “control circuitry whose continuity and energization or ability to operate are monitored and alarmed.” It is unclear whether or not it is acceptable to verify DC voltage at the actuating device trip terminals at least once every 12 calendar years for “unmonitored control circuitry associated with protective functions.” It is recommended that periodically verifying DC voltage in this manner be an acceptable means of accomplishing the maintenance activity identified in Table 1-5 for unmonitored control circuitry associated with protective functions.
		12. Referring to 4.2. Facilities of the draft standard, it is unclear whether protection systems for transformers that step down from over 100kV to below 15kV are applicable to the standard. Even if there are normally-open distribution feeder ties for purposes of transferring load in a make-before-break fashion, these transformers are generally not considered BES elements.
		13. Referring to 4.2.5 of the draft standard, it is unclear whether protection for generator excitation systems are applicable to the standard.

		14. It is unclear whether external timing relays (e.g., Zone 2) are considered control circuitry components (like lockout and auxiliary relays) or protective relay components.
Response:	**Thank you for your comments.**	
	1. The SDT agrees with your observation and has changed the relevant parts of the implementation plan to clarify that they apply to the maintenance activities for the relevant maintenance intervals	
	2. The SDT agrees with your observation and has revised the Implementation plan to clarify.	
	3. The trip paths from protective relays that respond to mechanical quantities and are intended to detect faults are a part of the Protection System control circuitry. The sensing elements are omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocols for these sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff. Note that trip signals from devices sensing mechanical parameters not directly indicative of an electrical fault need not be tested per this standard.	
	4. The SDT has removed parts 1.1 and 1.3 from Requirement R1, addressing part of your comment. The SDT agrees that PRC-005-2 allows some leeway in how an entity fulfills the testing requirements of the standard. Section 15 of the Supplementary Reference and FAQ document provides numerous examples of possible testing techniques for the various component types making up a Protection System. An entity's PSMP should clearly define how the testing requirements of the standard are fulfilled. The Measures for each requirement, as well as Section 15.8 of the Supplementary Reference and FAQ document, provide some examples of possible compliance documentation for completion of testing.	
	5. The SDT agrees with your suggestion and has changed the standard accordingly.	
	6. The entity has the authority to establish its own acceptable performance criteria. This criteria does not need to be in the PSMP, but should reside somewhere within the maintenance documentation.	

	7. As utilized on Table 1-4, the term “ohmic value” is a generic reference to the measurement of a battery cell or units ability to pass current flow. This may be done using conductance, resistance or impedance measurements; the various battery test equipment manufacturers use different measurement methods and the term “ohmic value” is meant to be technology neutral. See FAQ on page 78 of the Supplementary Reference and FAQ document. The term “resistance” as used in Table 1-4 refers specifically to the dc resistance of the battery terminal connections and the battery intercell/inter-unit physical connectors. See related FAQ on pages 74-75 of the Supplementary Reference and FAQ document.
	8. Battery terminal connection resistance is a measurement of the resistance of a connection at a battery terminal. Battery intercell or unit-to-unit connection resistance is a measurement of the resistance of the external conductor interconnecting two adjacent battery cells or two adjacent multi-cell battery units. The SDT believes these are common battery maintenance terms used throughout the industry.
	9. The SDT disagrees and believes that resistance as used in Table 1-4 is the appropriate term for the parameters to be measured and is consistent with standard battery system maintenance terminology.
	10. The SDT disagrees with your recommendation to standardize maintenance intervals between different battery types that have distinctly different failure mechanisms. See related FAQ on pages 80-81 of the Supplementary Reference and FAQ document for further discussion of requirements for ohmic measurements of VRLA batteries. Concerning your recommendation to allow for 7 calendar months, the SDT believes that the six-month interval specified is appropriate.
	11. The SDT has modified this specific portion of the Table, and believes that the modifications address your concern. Please see Section 15.3 of the Supplementary Reference and FAQ document for a discussion of this topic.
	12. The standard does not include the Protection Systems for transformers that step down from over 100kV to below 15kV if these transformers are not BES elements. If Protection Systems are installed for purposes of detecting Faults on BES elements, these Protection Systems are included.
	13. Paragraph 4.2.5.1 indicates that the excitation system protection system would only be in scope if the excitation system generates signals that trip the generator output breaker either directly or via lockout or auxiliary tripping relays.

	14. As timing is critical to proper Protection System function, timers are considered protective relays.	
Wisconsin Electric Power Co. Wisconsin Electric Power Marketing	Affirmative Ballot	Do we need to track the maintenance of another owner's Protection System Component which is part of my Protection System? For example, if our Protection System includes and trips another owner's circuit breaker, do we need to track maintenance and testing for that circuit breaker?
Response: Thank you for your comment and affirmative ballots. **The owner is responsible for the maintenance of Protection System Components. You do not need to track the maintenance of other owner's Protection System Components.**		
Beaches Energy Services	Negative Ballot	1. Standard requires 100% perfection, e.g., missing any one interval for any one piece of equipment leads to a violation. This is; however, mitigated by the fact that the intervals are long enough to allow implementation of business practices with shorter intervals to add some "buffer".

		2. The "Applicability" section is not consistent with the recent Y-W and Tri-State PRC-005 interpretation (Project 2009-17). The Applicability 4.2.1 states that the standard includes: "Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.)" whereas the Y-W and Tri-State interpretation basically says that "transmission Protection Systems" both detect AND trip BES Elements; Hence, the new standard alters the existing "and" statement in the Y-W and tri-State interpretation and eliminates the consideration of tripping BES Elements from applicability. This will have the consequence of including Protection Systems on step-down transformers that "look backwards" into the BES system as applicable to the standard. For instance, a distribution network fed from multiple transmission interconnections will have protective relaying (directional overcurrent most likely) to look backwards into the transmission system to trip the step-down transformer to prevent back-feed from the distribution network). This step-down transformer protection would be included in the new standard because it's purpose to the detect faults on the BES (event though the purpose of the protection is actually to protect overloading of the distribution and for worker safety on the BES); whereas the Y-W and Tri-State interpretation excludes that protection from the existing PRC-005-1 standard.

Response: Thank you for your comments.

1. **The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. The graded approach of the VSL for Requirement R3 allows the RE to provide discretion when assessing severity of the violation when only a relatively small number of maintenance activities have been missed.**
2. **The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion. If, as in your example, a protective relay is installed to prevent back feeding (rather than for detecting BES faults), it would not be applicable even if it has a secondary result of incidentally detecting faults on the BES.**

Florida Municipal Power Pool	Negative Ballot	1. Standard requires 100% perfection, e.g., missing any one interval for any one piece of equipment leads to a violation. This is; however, mitigated by the fact that the intervals are long enough to allow implementation of business practices with shorter intervals to add some "buffer", e.g., if the standard says an interval is 6 years, then, through business practice we can shorten actual maintenance and testing intervals to something like 4 years to allow ourselves a 2 year buffer to catch equipment that may have been missed due to difficulty in scheduling outages and the like. Does not cause us to vote negative.
	Negative Poll	2. The "Applicability" section is not consistent with the recent Y-W and Tri-State PRC-005 interpretation (Project 2009-17). The Applicability 4.2.1 states that the standard includes: "Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.)" whereas the Y-W and Tri-State interpretation basically says that "transmission Protection Systems" both detect AND trip BES Elements; Hence, the new standard alters the existing "and" statement in the Y-W and tri-State interpretation and eliminates the consideration of tripping BES Elements from applicability. This will have the consequence of including Protection Systems on step-down transformers that "look backwards" into the BES system as applicable to the standard. For instance, a distribution network fed from multiple transmission interconnections will have protective relaying (directional overcurrent most likely) to look backwards into the transmission system to trip the step-down transformer to prevent back-feed from the distribution network). This step-down transformer protection would be included in the new standard because it's purpose to the detect faults on the BES (event though the purpose of the protection is actually to protect overloading of the distribution and for worker safety on the BES); whereas the Y-W and Tri-State interpretation excludes that protection from the existing PRC-005-1 standard. Causes us to vote Negative.

<table>
<tr><td colspan="3">Response: Thank you for your comments.
1. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. The graded approach of the VSL for Requirement R3 allows the RE to provide discretion when assessing severity of the violation when only a relatively small number of maintenance activities have been missed.
2. The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, “transmission Protection System”, and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses “Protection Systems that are installed for the purpose of detecting faults on BES Elements.” Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion. If, as in your example, a protective relay is installed to prevent back feeding (rather than for detecting BES faults), it would not be applicable even if it has a secondary result of incidentally detecting faults on the BES.</td></tr>
<tr><td>Constellation Power Source Generation, Inc.</td><td>Negative Ballot
Negative Poll</td><td>Constellation Power Generation is voting against the approval of this standard because, from a generation perspective, the maintenance intervals and activities described in all of the Tables are too prescriptive. Constellation Power Generation is concerned that the Tables may conflict with the existing PSMPs built by Registered Entities based on years of operational experience with the testing methods and testing frequencies that work best for the specific asset. In the worst case, the specifics dictated in the Tables may move Entities away from more stringent PSMPs that are currently in practice. For this reason, Constellation Power Generation suggests that the drafting team revisit the concept of the Tables to better convey useful guidance without creating a compliance requirement that may be contrary to improved reliability. The Registered Entity should be given more flexibility to dictate how a protection system component should be tested, and at what frequency. Furthermore, the technical manpower and compliance documentation demands to implement a performance based protection system maintenance program are so onerous that it is highly unlikely that any small generation entity would use it. Please refer to Constellation Power Generation’s submitted comments for other issues identified with this standard.</td></tr>
<tr><td colspan="3">Response: Thank you for your comment.
FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that may be consistently monitored for compliance.</td></tr>
</table>

Duke Energy/ Fort Pierce Utilities Authority	Negative Ballot	Duke Energy disagrees with the wording in the Applicability section 4.2.1. The wording change from PRC-005-2 draft 4 to PRC-005-2 draft 5 expands the reach of the standard to relaying schemes that detect faults on the BES but are not intended to provide protection for the BES. Duke Energy's standard protection scheme for dispersed generation at retail stations would be subject to the standard due to the changes in section 4.2.1. These protection schemes are design to detect faults on the BES, but do not operate BES elements nor do they interrupt network current flow from the BES. In the most recent draft the relays, current transformers, potential transformers, trip paths, auxiliary relays, batteries, and communication equipment associated with the dispersed generation protection scheme would be subject to the requirements in PRC-005-2. Previous drafts of the standard would not have required Duke Energy to maintain the protection system components associated with dispersed generation schemes at retail stations in accordance to the requirements in PRC-005-2. The new wording in section 4.2.1 would add significant O&M costs and resource constraints due to the inclusion of protection system devices at retail stations without increasing the reliability of the BES. Duke Energy does not believe it was the intent of the standard to include elements that did not have an impact on the reliability of the BES. Duke Energy would prefer the definition used in PRC-005-1A Appendix 1 "any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES."
Response: Thank you for your comment. **The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.**		

Lakeland Electric	Negative Ballot	First Concern is that evidence of maintenance and testing at this level will be very difficult to obtain, track and report. Second is the word exercise - what is really meant by this. This may be difficult or impossible to do without impacting or tripping the circuit. The "Applicability" section is not consistent with the recent Y-W and Tri-State PRC-005 interpretation (Project 2009-17).
Response: Thank you for your comments 1. **FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that may be consistently monitored for compliance. Nonetheless, the SDT agrees that significant effort will be necessary to implement these requirements and to prove compliance.** 2. **The SDT is unsure to which utilization of the word "exercise" you refer.** 3. **The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.**		
Illinois Municipal Electric Agency	Negative Ballot	IMEA greatly appreciates SDT efforts to address/resolve issues, improve PRC-005, and consolidate various PRC Reliability Standards. However, IMEA is voting Negative based on the inconsistency between the current Applicability language and the PRC-004 and PRC-005 interpreation (Project 2009-17) recently approved by FERC. IMEA supports comments submitted by Florida Municipal Power Agency which address this inconsistency, and encourages the SDT to address this issue which is important to municipal entities.

Response: Thank you for your comment. **The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion. If, as in your example, a protective relay is installed to prevent back feeding (rather than for detecting BES faults), it would not be applicable even if it has a secondary result of incidentally detecting faults on the BES.**		
Consumers Energy	Negative Ballot	R3 continues to have "...initiate resolution of unresolved maintenance issues." Initiate means to start or set going, it does not mean closure of the item. If a remediation project is initiated and not closed out in a timely manner an auditor could penalize an entity based on what the auditor considers timely. We suggest definitive language indicating closure of the unresolved maintenance issue. Also, it would be beneficial to specify time frame for closing the issue.
Response: Thank you for your comment. **PRC-005-2 only requires the entity "… initiate resolution" of the issue found. The SDT recognizes that performance of the activities necessary to resolve an issue are entirely dependent upon the circumstances surrounding that issue and, consequently, will require varying amounts of resources and time to complete the process. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues. Demonstrating the entity has initiated resolution can include such things as documentation of a work order, replacement component order, invoice, or purchase order, etc… Producing evidence of this nature would then indicate adherence to the requirement.**		

Florida Keys Electric Cooperative Assoc.	Negative Ballot	The "Applicability" section is not consistent with the recent Y-W and Tri-State PRC-005 interpretation (Project 2009-17). The Applicability 4.2.1 states that the standard includes: "Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.)" whereas the Y-W and Tri-State interpretation basically says that "transmission Protection Systems" both detect AND trip BES Elements; Hence, the new standard alters the existing "and" statement in the Y-W and tri-State interpretation and eliminates the consideration of tripping BES Elements from applicability. This will have the consequence of including Protection Systems on step-down transformers that "look backwards" into the BES system as applicable to the standard. For instance, a distribution network fed from multiple transmission interconnections will have protective relaying (directional overcurrent most likely) to look backwards into the transmission system to trip the step-down transformer to prevent back-feed from the distribution network). This step-down transformer protection would be included in the new standard because it's purpose to the detect faults on the BES (event though the purpose of the protection is actually to protect overloading of the distribution and for worker safety on the BES); whereas the Y-W and Tri-State interpretation excludes that protection from the existing PRC-005-1 standard.
Response: Thank you for your comment. **The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.**		

Independent Electricity System Operator	Negative Ballot	The IESO disagrees with the concept that auditors use the standards as minimum requirements and evaluate compliance based on a registered entity's own governance. We believe that the entity could be found non-compliant with Requirement R3 if they fail to follow the internal maintenance intervals established in their PSMP, even though actual maintenance intervals are no less frequent than the prescribed maximum intervals established in the draft standard. The potential for such a finding will discourage conscientious entities from setting higher internal targets for their planned maintenance and promote compliance with only the minimum requirements of the standard. We therefore propose the following revision to Requirement R3: R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement and follow its PSMP and initiate resolution of any unresolved maintenance issues. In the case of time-based maintenance programs, each Transmission Owner, Generator Owner, and Distribution Provider is permitted to deviate from its PSMP provided that actual maintenance intervals do not exceed those specified in Tables 1-1 through 1-5, Table 2 and Table 3. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
Response: The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Florida Municipal Power Agency	Negative Ballot	We have three remaining concerns. The second concern leads us to recommend a negative vote.

	Negative Poll	1. Standard requires 100% perfection, e.g., missing any one interval for any one piece of equipment leads to a violation. This is; however, mitigated by the fact that the intervals are long enough to allow implementation of business practices with shorter intervals to add some "buffer", e.g., if the standard says an interval is 6 years, then, through business practice we can shorten actual maintenance and testing intervals to something like 4 years to allow ourselves a 2 year buffer to catch equipment that may have been missed due to difficulty in scheduling outages and the like. Does not cause us to vote negative.
		2. The "Applicability" section is not consistent with the recent Y-W and Tri-State PRC-005 interpretation (Project 2009-17). The Applicability 4.2.1 states that the standard includes: "Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.)" whereas the Y-W and Tri-State interpretation basically says that "transmission Protection Systems" both detect AND trip BES Elements; Hence, the new standard alters the existing "and" statement in the Y-W and tri-State interpretation and eliminates the consideration of tripping BES Elements from applicability. This will have the consequence of including Protection Systems on step-down transformers that "look backwards" into the BES system as applicable to the standard. For instance, a distribution network fed from multiple transmission interconnections will have protective relaying (directional overcurrent most likely) to look backwards into the transmission system to trip the step-down transformer to prevent back-feed from the distribution network). This step-down transformer protection would be included in the new standard because it's purpose to the detect faults on the BES (event though the purpose of the protection is actually to protect overloading of the distribution and for worker safety on the BES); whereas the Y-W and Tri-State interpretation excludes that protection from the existing PRC-005-1 standard. Causes us to vote Negative.

		3. The standard reaches further into the distribution system than we would like for UFLS and UVLS (Table 3). We have two parts to this concern. First, it will be somewhat onerous to present all the evidence of distribution class protection system maintenance and testing at audits. And second, our biggest concern is in the testing required to "exercise" a lockout or tripping relay. This may require installation of test blocks to allow such exercising of the lockout or tripping relay without tripping the distribution circuit, and such a test could be difficult to perform without impacting customer continuity of service if the lockout/tripping relay for the UFLS is the same as the lockout/tripping relay for distribution fault protection. However, most of FMPA's members have microprocessor-based relays for distribution circuits with the UFLS / UVLS embedded within the microprocessor based relay where the path from the UFLS / UVLS relay to the lockout / tripping relay is internal to the micro-processor based relay, so, testing the UFLS/UVLS relay will at the same time test the internal lockout / switching relay. However, for older electro-mechanical UFLS schemes, this type of testing could be problematic. Borderline concerning whether this causes us to vote Negative or not. As a result, FMPA recommends a Negative vote with the second and third comments, emphasizing that it is the second comment that causes us to vote negative but we also would like the 3rd comment addressed. Feedback appreciated. Vote and comments are due next Wednesday, 9/28.

Response: Thank you for your comments 1. **The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. The graded approach of the VSL for Requirement R3 allows the RE to provide discretion when assessing severity of the violation when only a relatively small number of maintenance activities have been missed.** 2. **The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ Document for additional discussion. If, as in your example, a protective relay is installed to prevent back feeding (rather than for detecting BES faults), it would not be applicable even if it has a secondary result of incidentally detecting faults on the BES.** 3. **UVLS and UFLS systems are required to be included as part of the Project 2007-17 Standard Authorization Request (SAR). The SDT believes that electromechanical lockout relays require periodic operation. As such, these devices are required to be exercised at the 12 year interval for UVLS and UFLS systems. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed.**		
Lakeland Electric	Negative Poll	The "Applicability" section is not consistent with Tri-State PRC-005 interpretation.
Response: Thank you for your comments **The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.**		

Liberty Electric Power LLC	Negative Ballot	With the development and publication of maximum maintenance and testing intervals (the Tables), there is no longer a reliability need for a RE to identify the associated time-based maintenance intervals for Protection System Components. Further, REs who wish to perform these activities in shorter intervals than those allowed by the standard risk non-compliance (See Supplementary Reference, page 27,"If your PSMP (plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard.")If the entity completes all activities within the maximum interval allowed by the standard, there can be no reliability concern; if there is a reliability issue, then the table interval is incorrect. I would suggest the following changes.
		1. Change R1.2 to read "Identify any Protection System component where the RE is using a performance based maintenance interval. No batteries associated with the station DC supply component type of Protection System shall be included in a performance based system"
		2. Change R1.3 to read "The intervals for time-based programs are established in Table 1-1 through 1-5, Table 2, and Table 3".
		3. Change M1 to add the phrase "for performance-based components" after the words "maintenance intervals".
		4. In M1, replace the words "the type of maintenance program applied (time-based, performance based, or a combination of these maintenance methods") with the words "the identification of any protection system components using performance based intervals".
Response: The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues. The Measures have also been revised.		
Manitoba Hydro	Negative Ballot	Manitoba Hydro is voting negative for the following reasons:

		1. Grace Periods Grace periods should be permitted on the maintenance time intervals. While we understand that grace periods can be built into a PSMP, maintenance decisions that compromise reliability may still have to be made just to meet the specified time intervals and avoid penalty. An example of this would be removing a hydraulic generator from service at a time of low reserve to meet a maintenance interval and avoid non-compliance. Grace periods are also required in the case of extreme weather conditions. Such conditions may make it unsafe to perform maintenance within the maintenance interval (for example, performing a battery inspection at a remote station during severe winter weather) or may create a risk to reliability if the equipment being maintained is removed from service during these conditions. Utilities need to retain a reasonable amount of discretion and flexibility to make maintenance decisions that are best for safety and reliability without risking non-compliance. In addition, we disagree with the basis that the Drafting Team has established that grace periods are not permitted because of FERC Order 693 which requires that 'maximum' time intervals are established within PRC-005-2. With grace periods, a maximum time interval obviously becomes the required maintenance interval plus the maximum permitted grace period. So we strongly feel that grace periods can be added to the standard while adhering to the FERC Order. We also disagree with the line of reasoning that the Drafting Team used to establish the maximum maintenance intervals for relays as outlined on page 38 of the Supplementary Reference and FAQ document. To our knowledge, no document has been produced which provides evidence of maximum time intervals that work well for 'maintenance cycles that have been in use in generator plants for decades'. Our Protection Systems Maintenance experience indicates that the proposed intervals are acceptable as nominal time intervals with grace periods, but not as maximum time intervals without grace periods. Without a grace period, the bulk of protection maintenance on a six year maintenance cycle will have to be done one year earlier than previously required, in order to allow for the last year of the maximum interval to be used as the grace period. Manitoba Hydro considers this an unnecessary burden on resources with no benefit to reliability. Manitoba Hydro recommends that grace periods be permitted within PRC-005-2 if an entity can demonstrate a reliability or safety related need for using a grace period. This would require the Drafting Team to develop reliability-related criteria for using a grace period.

		2. Phased Implementation Plan Manitoba Hydro does not agree with the prescribed phased implementation plan. Entities should be given a single compliance date for each of the maintenance intervals, and be allowed the flexibility to schedule and complete their maintenance as required while transitioning to the defined time intervals in PRC-005-2. For example, if a maximum maintenance interval is 6 calendar years, the implementation plan should only require that "The entity shall be 100% compliant on the first day of the first calendar quarter 84 months following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter 96 months following Board of Trustees adoption." (item 4c.). The existing standard PRC-005-1 already requires protection systems to be maintained as part of a program. Prescribing how an entity must reach full compliance will provide a negligible improvement in reliability, while significantly increasing the compliance burden. PRC-005-2 affects a large number of assets, and proving compliance for prescribed percentages of assets during the transition period creates unnecessary overhead with no added value. We suggest that items 3a., 3b., 4a., 4b., 5a. and 5b be removed from the implementation plan and that NERC measure progress on reaching PRC-005-2 intervals using means other than Compliance measures such as industry surveys.

Response: Thank you for your comments.

1. **FERC Order 693 directs NERC to establish maximum allowable intervals. The SDT believes a "grace period" process as you describe would not satisfy this directive. In essence, by specifying maximum allowable intervals the SDT is leaving the establishment of normal maintenance intervals and grace periods to the entities discretion and to what works best for their scheduling needs and program flexibility. Alternatively, if the SDT believes that 6 calendar years is the maximum allowable interval for a given maintenance activity, it could have done as you suggested and defined a 4 year "normal" interval with a 2 year grace period for a maximum allowable interval of 6 years. The SDT believes the management of normal maintenance intervals and grace periods is best left to the entity's PSMP and thus chose only to specify the maximum allowed interval within which entities must comply. Note that if data is available to prove reliability is maintained, performance-based maintenance is available to achieve longer maintenance intervals.**
2. **The SDT believes that it is not practical for all entities to rapidly transition all of their Protection Systems to the new program, especially with some component types on maintenance intervals of up to 12 years. Nonetheless, all in-scope Protection Systems must be maintained by either a PRC-005-1 program or a PRC-005-2 program. The SDT believes the phased approach mapped out in the Implementation plan is practical. If an entity wishes to implement PRC-005-2 on a more rapid rate than laid out in the Implementation plan to lessen the complexity of documentation requirements, they are free to do so.**

Muscatine Power & Water	Negative Ballot	1. Section D.1.3, in Data Retention, requires an entity to retain the two most recent performances of each distinct maintenance activity. This is an unreasonable and problematic requirement and does not enhance reliability. Recommend the data retention be changed to require only the most recent test record. A compliance audit should be focused on the present day and not in the past. PRC-005-2 allows testing intervals of up to 12 calendar years. If we are required to have the two most recent test results, we could conceivably have to retain a relay test record for up to 24 years! Hypothetically, if we have a test record from ten years ago, but we do not have the record from 12 years before that, how does that adversely affect the reliability of the BES today? The standard should focus on – Is the Entity compliant TODAY?
		2. Table 1-5 requires a maintenance activity to, "Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Recommend this be changed to, "Verify that a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Alternately, change the wording to, "Electrically operate each interrupting device every 6 years." While requiring each trip coil to operate the breaker sounds good in theory, however, it creates issues in the field and may create more problems than it solves. The trip coils are located in the panel at the breaker and are not configured to test independently. Isolating one trip coil from the other may include "lifting a wire" that may not get landed properly when the test is complete. Using an actual event only tests one coil and we may not know which coil tripped the device. The current language is a recipe for a compliance violation. The standard should focus on ensuring the control circuitry is intact and trips the breaker without injecting additional, unneeded risk to the BES.
		3. In the tables for dc Supply the term "unit-to-unit" is used along with "intercell" when referring to measurement of connection resistance. From the applicable IEEE standards (e.g. IEEE 450), the standard terminology seems to be "intercell". It is recommended that the "unit-to-unit" term be removed to avoid confusion regarding what is to be verified.

<table>
<tr><td colspan="3">

Response: Thank you for your comments.

1. **In order that a Compliance Monitor can be assured of compliance, the SDT believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted standard to establish this level of documentation. This seems to be consistent with the current practices of several Regional Entities. Obviously, Compliance Monitors should not expect entities to be able produce records for maintenance performed prior to there being requirements for that maintenance to be performed.**
2. **The description of the configuration of the second trip coil on circuit breakers you have provided is not typical of the redundant approach taken by most entities. Typically, second trip coils are electrically isolated from the first trip coil and are often fed by a separately fused dc control circuit with different relay trip output, lockout and auxiliary tripping contacts utilized in each circuit. The SDT believes that it is important that redundant trip paths be maintained within the indicated interval, and the prescribed interval already considers the reliability benefits of redundant equipment.**
3. **The term “unit-to-unit” is used for the conductor utilized to connect one multi-celled battery jar to an adjacent multi-celled battery jar.**

</td></tr>
<tr><td>NorthWestern Energy</td><td>Negative Ballot</td><td>

I recommend a no vote please see my comments below.

1. For Table 1-5 Trip coils or actuators of circuit breakers, interrupting devices, or mitigating devices 6 calendar years Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device. Provisions need to be added to allow non-tripping checks of coils on the BES element that will Trip load. If I am reading the purposed correct the circuit switcher feeding distribution banks at or above 100kV will need to be tripped taking out load.

2. It was my understanding the IEEE standard 450 allowed for 7 year load test interval for VLA and NiCad batteries the standard calls out for 6 years. It appears that the standard has been recently updated and should be verified. My last objection is Table 1-2

3. Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below. 4 calendar months Verify that the communications system is functional. 4 calendar months is excessive on annual maint and will discourage communications assisted tripping when not absolutely needed. 1 year is a more reasonable and doable timeline.

</td></tr>
</table>

Response: Thank you for your comments. **1. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." If the Protection System in question is not protecting a BES component, it is not applicable to this standard. Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.** **2. IEEE 450 only pertains to VLA batteries. IEEE 1106 pertains to NiCad batteries. The SDT believes that the 6 calendar year interval specified in PRC-005-2 is appropriate.** **3. The SDT believes that performing this maintenance activity at 4 month intervals is proper for unmonitored communications systems.**		
Seattle City Light	Negative Ballot	Regarding Voltage and Current Sensing Device Maintenance & Testing Activities: Table 1-3 of the standard lists the minimum required maintenance activities for voltage and current sensing devices as "Verify that current and voltage signal values are provided to the protective relay." Consistent with Table 1-3, Section 15.2.1 of the Supplementary Reference states that an entity "...must verify that the protective relay is receiving the expected values from the voltage and current sensing devices..." The Supplementary Reference further offers examples of how this requirement may be satisfied with most of the examples reference the need to verify the signal at each relay in the circuit. We recognize the need to verify a voltage signal at each protective relay, as these devices are wired in parallel and an open circuit at one location may not impact the other devices on the circuit. However, we do not agree that there is a need to verify a current signal at each protective relay. Current devices are wired in series; an open circuit at any location will impact all other devices on the circuit. For this reason, a single measurement of the current circuit is sufficient. We recommend updating Table 1-3 and the supplementary reference to account for the different physical characteristics of voltage and current circuits.
Response: Thank you for your comment. **An open circuit is not the only failure mechanism for a CT secondary circuit. Grounded CT secondary wiring can result in situations where accurate current is present in the part of the secondary circuit upstream of the ground but current would be shunted to ground and might not pass through devices downstream of the ground. Entities should not interpret PRC-005-2 as specifying "how" to test but rather that PRC-005-2 only specifies "what" to test.**		

Seminole Electric Cooperative, Inc.	Negative Ballot	We recommend the SDT consider an interval of 12 calendar years for the component in row 3, of Table 1-5 on page 19 of the standard. The maximum maintenance interval for "Electromechanical lockout and/or tripping devices which are directly in a trip path from the protective relay to the interrupting device trip coil" should be consistent with the "Unmonitored control circuit" interval which is 12 calendar years. In order to test the lockout relays, it may be necessary to take a bus outage (due to lack of redundancy and associated stability issues with delayed clearing). Increasing the frequency of bus outages (with associated lines or transformers) will also increase the amount of time that the BES is in a less intact system configuration. Increasing the time the BES is in a less intact system configuration also increases the probability of a low frequency, high impact event occurring. Therefore, the Maximum Maintenance Interval should be 12 years for lockout relays. We believe that, as written, the testing of "each" trip coil and the proposed maintenance interval for lockout testing will result in the increased amount of time that the BES is in a less intact system configuration. We sincerely hope that the SDT will consider these changes.
Response: Thank you for your comments. **The SDT believes it is possible to manage the risks that you describe and that performance of this testing will be an overall benefit to the reliability of the BES. It is the majority opinion of the subject matter experts forming the SDT that testing of electromechanical devices with moving parts such as lockout relays be performed on a 6 year interval. Entities may use the PBM process to extend this interval if they desire.**		
Tennessee Valley Authority	Negative Ballot	It will take several years for TVA to implement checkback on 590 carrier blocking sets on the TVA system and not have to perform the PRC 005-2 requirement of verifying functionality every 4 months with no grace period. TVA carrier failure rate has not increased since the frequency was changed in January 2008 from 4 tests/year to 2 tests/year. We are also implementing an extensive PM test in October 2011 which will test 25% of the sets per year and will take readings of SWR, line loss, and receiver margin.
Response: Thank you for your comment. **The SDT believes that performing this maintenance activity at 4 month intervals will benefit the reliability of the BES. The Implementation plan allows for 15 months after regulatory approvals for entities to implement the program per PRC-005-2. You may also find performance-based maintenance (per Requirement R2) useful.**		

Utility Services, Inc.	Negative Ballot	While we generally agree with most of the proposal, we are concerned about the need to address validate of Protection System settings in the standard. We believe that there should be an explicit requirement on validating the settings to ensure that misoperations don't occur due to incorrect settings being programmed into the devices. Reliability will be enhanced if misoperations can be avoided due to the explicit check on the accuracy of the settings.
Response: Thank you for your comment. **Rows 1 and 2 of Table 1-1 currently require verification that relay settings are as specified.**		
Westar Energy	Negative Ballot	Westar agrees in general with most of the changes and modifications included in the proposed Standard. Specifically, the change from 3 to 4 calendar months in Table 1-4. 1. However, we believe that the terms Distributed and Non-Distributed need to be more clearly defined. 2. Clarification is also needed on an entities ability to use fault initiated trips as evidence for Table 1-5 - Control Circuitry.
Response: Thank you for your comments. **1. Please see Section 8.1.1 on pg 25-26 of the Supplementary Reference and FAQ document for discussions of the terms “distributed” and “non-distributed”.** **2. Please see paragraph 7 in Section 8.1.2 of the Supplementary Reference and FAQ document for further discussion of this topic.**		
Xcel Energy, Inc.	Negative Ballot	The VSL for R3 is confusing because of the lack of a specified time horizon. Are the percentages quoted on an annual schedule basis, an audit period, or a continuous percentage measurement of any previously scheduled maintenance activities? Greater clarity is needed on the intent of this VSL.
Response: Thank you for your comment. **The VSLs that use a graduated VSL have been revised based, in part, on the comments you have provided. The percentages relate to the number of violations reported within the compliance monitoring period relative to the number of components within that component type.**		

Xcel Energy, Inc.	Negative Ballot	I appreciate the effort the SDT has invested in bringing PRC-005 to ballot and refer them to comments submitted by FirstEnergy. I agree with FE that PRC-005 encourages entities to set a low bar when developing protective system maintenance programs and will penalize those with robust programs that miss self-imposed schedules or targets.
Response: The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
Tennessee Valley Authority	Negative Ballot	1. It will take several years for TVA to implement checkback on 590 carrier blocking sets on the TVA system and not have to perform the PRC 005-2 requirement of verifying functionality every 4 months with no grace period. TVA carrier failure rate has not increased since the frequency was changed in January 2008 from 4 tests/year to 2 tests/year. We are also implementing an extensive PM test in October 2011 which will test 25% of the sets per year and will take readings of SWR, line loss, and receiver margin.
		2. TVA disagrees with the requirement to measure internal ohmic values of the station dc supply batteries every 18 months. The interval should be 36 months. Our experience from performing our routine maintenance program including cell impedance testing at 3-year intervals has been that the program is fully adequate in monitoring bank condition. An 18-month interval for internal resistance/impedance testing is an unnecessary burden.
		3. Are we required to test the trip circuit between the power transformer sudden pressure relay and the switch house or are we only required to test the trip circuit between the electrical sensing relays and the trip coils of the breakers?

Response: Thank you for your comments. 1. **The SDT feels that performing this maintenance activity at 4 month intervals will benefit the reliability of the BES. The Implementation Plan allows for 15 months after regulatory approvals for entities to implement the program per PRC-005-2. You may also find that performance-based maintenance (per Requirement R2) useful.** 2. **The SDT believes the required 18 month interval is better in line with accepted industry practice. Please note that for VLA batteries, an entity may entirely avoid internal ohmic measurements by implementing a VLA maintenance program using 18 month visual inspections and 6 yr capacity tests.** 3. **The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff.**		
Northeast Power Coordinating Council		The focus of the industry is on the field procedures necessary to ensure that protection systems are maintained and tested. This includes the verification that settings have been applied correctly. The accuracy of the settings calculated needs to be validated, and that step should be considered for inclusion in this Standard.
Response: Thank you for comment. **Validating the accuracy of settings calculations is more properly a design function and not a maintenance function. The SDT agrees that validating relays are left with the intended settings programmed in is important; as such, Row 1 and Row 2 of Table 1-1 require that settings be verified to be as specified.**		

PNGC Comment Group		Thank you for the opportunity to comment on the draft Standard PRC-005-2 - Protection System Maintenance. While the feedback from the last round of comments is appreciated, we still cannot support the standard as written due to our concerns outlined here. We appreciate the work that NERC has put into a new standard to encapsulate and replace the current PRC-005, PRC-008, PRC-011 and PRC-017. But, we believe that the draft Standard needs one important revision before the NERC Board of Trustees should approve it. Specifically, NERC should revise the draft version of PRC-005-2 so that the beginning of Section 4.2 reads as follows: "4. 2. Facilities:Protection Systems that (1) are not facilities used in the local distribution of electricity, (2) are facilities and control systems necessary for operating an interconnected electric energy transmission network, and (3) are any of the following:"This revision is necessary to capture the limits that Congress placed on FERC, NERC, and the Regional Entities in developing and enforcing mandatory reliability standards. Specifically, Section 215(i) of the Federal Power Act provides that the Electric Reliability Organization (ERO) "shall have authority to develop and enforce compliance with reliability standards for only the Bulk-Power System." And, Section 215(a)(1) of the statute defines the term "Bulk-Power System" or "BPS" as: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy." With this language, Congress expressly limited FERC, NERC, and the Regional Entities' jurisdiction with regard to local distribution facilities as well as those facilities not necessary for operating a transmission network. Given that these facilities are statutorily excluded from the definition of the BPS, reliability standards may not be developed or enforced for facilities used in local distribution. In Order No. 672, FERC adopted the statutory definition of the BPS. In Order No. 743-A, issued earlier this year, the Commission acknowledged that "Congress has specifically exempted 'facilities used in the local distribution of electric energy'" from the BPS definition. FERC also held that to the extent any facility is a facility used in the local distribution of electric energy, it is exempted from the requirements of Section 215. In Order No. 743-A, FERC delegated to NERC the task of proposing for FERC approval criteria and a process to identify the facilities used in local distribution that will be excluded from NERC and FERC regulation. The critical first step in this process is for NERC to propose criteria for approval by FERC to determine which facilities are used in local distribution, and are therefore not BPS facilities. The criteria to be developed by NERC must exclude any facilities that are used in the local distribution of electric energy, because all such facilities are beyond the scope of the statutory definition of the BPS, which establishes the limit of FERC and NERC jurisdiction. Accordingly, it is critical that NERC draft the new PRC-005-2 standard to expressly exclude facilities used in local distribution. NERC must also expressly exclude from PRC-005-2 those facilities "not necessary for operating an interconnected electric energy transmission network (or any portion thereof)". Similar to the local distribution exclusion, the facilities not necessary for operating a transmission network are not part of the BPS and therefore must be expressly excluded from the standard. We understand, but disagree with, the argument that, because the FPA clearly excludes local distribution facilities and facilities necessary for operating an interconnected electric transmission network from FERC, NERC, and Regional Entity jurisdiction, it is not necessary to expressly exclude these facilities again in reliability standards. This approach might be legally accurate, but could lead to significant confusion for entities attempting to implement the new PRC-005-2 standard. There are numerous examples of Regional Entities, particularly WECC, attempting to assert jurisdiction over such facilities, and regulated entities face significant uncertainty as to which facilities they should consider as within jurisdiction. Clarifying FERC, NERC, and Regional Entity jurisdiction in the BES definition, even if such clarification is already provided in the FPA, would avoid such problems under the new PRC-005-2 standard. Again, we appreciate the work NERC has put in so far on a new Standard. We look forward to working within the drafting process to help implement our recommended revision.

Response: Thank you for your comment.

Other than the requirement relating expressly to UFLS/UVLS Protection Systems, the Applicability currently expressly addresses Protection Systems applied for the purpose of detecting BES faults.

To the degree that such Protection Systems may be located on non-BES components, and as the Applicability addresses UFLS/UVLS systems, the SDT has received the following position from NERC Legal:

While UFLS and UVLS equipment are located on the distribution network, their job is to protect the Bulk Electric System. This is not beyond the scope of NERC's 215 authority.

FPA section 215(a) definitions section defines "bulk-power system as (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition then is limited by a later statement which adds the term bulk-power system "does not include facilities used in the local distribution of electric energy." Also, section 215 covers users, owners, and operators of bulk-power facilities.

UFLS and UVLS (when the UVLS is installed to prevent system voltage collapse or voltage instability for BES reliability) are not "used in the local distribution of electric energy" despite their location on local distribution networks. Further, if UFLS/UVLS facilities were not covered by the Reliability Standards, then in order to protect the integrity of the BES during under-frequency or under-voltage events, that load would have to be shed at the transmission bus to ensure the load-generation balance and voltage stability is maintained on the BES.

Bonneville Power Administration		1. BPA understands that the VSLs for R3 are based on the percentage of unresolved maintenance issues that an entity has failed to initiate a resolution for. This approach penalizes an entity for having less unresolved maintenance issues. For example, if an entity has only one unresolved maintenance issue and it failed to initiate a resolution for it, it would have failed to initiate a resolution for 100% of its unresolved maintenance issues, which would be a severe VSL. If another entity had 100 unresolved maintenance issues, and it failed to initiate resolution on ten of them, it would have failed to initiate a resolution on 10% of its unresolved maintenance issues, which would be a high VSL. Most likely, the first entity is doing a better job with its maintenance than the second entity, but the first entity receives a more severe penalty. The VSL for R3 is not an accurate measurement of a maintenance program's effectiveness and needs to be revised. BPA recommends removing the entire "Unresolved Maintenance Issue" topic from the standard. 2. In Table 1-1, it is not clear when a microprocessor relay meets the requirement for internal self-diagnosis and alarming. It is not clear that any microprocessor relay with a relay failure alarm would meet this requirement. 3. BPA believes that it seems like an omission in Table 1-1 for unmonitored microprocessor relays, the verification of settings is not included as a maintenance activity. 4. BPA would also like to recommend clarifying language stating that the owner of the asset is the responsible entity.

Response: Thank you for your comments. 1. **The SDT believes that, if a component cannot be returned to "good working order" during the performance of the maintenance program as defined within the entity's criteria, the maintenance program must include those actions necessary to restore the component (and thus the Protection System) to good working order. Therefore, the topic of "Unresolved Maintenance Issues" cannot be removed from the standard. The VSL for the old Requirement R3 (now Requirement R5) has been revised to indicate gradations on the actual count of violations of this requirement, rather than percentages.** 2. **Microprocessor relay failure alarms meet this requirement as long as the alarm is sent back to a location where corrective action can be initiated.** 3. **The first maintenance activity listed on Table 1-1 is to validate that relay settings are as specified and this statement is applicable to unmonitored microprocessor relays. The activity has been revised to clarify.** 4. **The preface paragraphs for R1, R2, R3, R4, and R5 each state that the Transmission Owner, Generator Owner, and Distribution Provider are responsible for implementation of the associated requirements.**		
FirstEnergy		1. We remain concerned with the proposed draft version of Requirement R3 as well as the SDT developed statements in the Supplementary Reference & FAQ. The SDT's approach sends industry the wrong message; a message that entities should not go beyond what is in the text of the standards and that in some cases they can even be found non-compliant by failing to meet their own more stringent internal practice. We have sent NERC Staff and Drafting Team leaders a separate document detailing our concerns as well as proposed redlines to the standard. The separately provided document can be viewed as FE's ballot comments.

		2. FE supports the standard from a technical standpoint but offer the following additional comments and suggestions: A clarification to the supplementary reference document is necessary regarding Maintenance Activities specified for electromechanical lockout and/or tripping auxiliary devices, as specified in Table 1-5 of the standard. The standard states, “Verify electrical operation of electromechanical trip and auxiliary tripping devices” which must be performed every 6 years. A question was asked during the September 15th Webinar requesting clarification of what “verify electrical operation....” meant. The verbal response from the SDT member was that this involves verifying that the relay actuates, but does not require verification that its contacts changed state. However, the answer to the question at the bottom of page 29 and top of page 30 in the Supplementary Reference and FAQ (dated July 29, 2011) implies that checking the contacts is necessary. The following statement in the published answer makes this clarification request necessary; “Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this Standard, to be checked.” This statement implies that if outputs to annunciators and DME inputs do not need to be checked, then the other outputs do need to be checked. Verification of the auxiliary tripping relays appears to be covered in Table 1-5 of the standard under the "Unmonitored control circuitry associated with protective functions" section at 12 calendar years. Thus, we ask the SDT clarify in the supplementary reference the type of maintenance activities required for electromechanical lockout and/or tripping auxiliary devices to satisfy the requirements of Table 1-5 of the standard. Since the standard specifically dictates the output contacts verification for protective relays under Table 1-1, the output contacts of aux tripping relays is left up to interpretation. Therefore, we suggest the following statement be added after “Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this Standard, to be checked.” on page 30 of the document: “Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the ‘Unmonitored control circuitry associated with protective functions" section’ at 12 calendar years.”

Response: Thank you for your comments. **1. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.** **2. Output contacts and auxiliary tripping relays that are not part of a trip path or essential for proper operation of an SPS need not be tested per this standard. The Supplementary Reference and FAQ document will be revised as you suggest.**		
Southwest Power Pool Standards Review Group		1. Please update Appendix B, Drafting Team Members, of the Supplementary Reference document. 2. We request that the detail for the breaker failure protection for generator protection in the bulleted list at the bottom of page 31 and the top of page 32 of the Supplementary Reference document be removed. We are not sure what the SDT is looking for here since there are several types of breaker failure protection. 3. We ask that Section 4.2.5.4 of the draft standard under the Facilities be modified to read 'Protection Systems that trip the generator for generator-connected station service transformers for generators that are part of the BES.' 4. We suggest that Section 1.3 Data Retention be rewritten to provide clarification that no data prior to the date of the last audit need be retained.

Response: Thank you for your comments. **1. The list of SDT members has been updated.** **2. The preface to the list of relays to which you refer is as follows: "Examples of typical devices and systems that may directly trip the generator, or trip through a lockout relay may include but are not necessarily limited to:". The SDT was merely attempting to provide a list of possible relays that might need to be included. The list is not meant to be all inclusive nor do all relays of the types on the list necessarily need to be included.** **3. In consideration of your comment and those of others received, the SDT has revised Section 4.2.5.4 as requested.** **4. In order that a Compliance Monitor can be assured of compliance, the SDT believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted standard to establish this level of documentation. This seems to be consistent with the current practices of several Regional Entities.**		
Florida Municipal Power Agency		The "Applicability" section is not consistent with the recent Y-W and Tri-State PRC-005 interpretation (Project 2009-17). The Applicability 4.2.1 states that the standard includes: "Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.)" whereas the Y-W and Tri-State interpretation basically says that "transmission Protection Systems" both detect AND trip BES Elements; Hence, the new standard alters the existing "and" statement in the Y-W and tri-State interpretation and eliminates the consideration of tripping BES Elements from applicability. This will have the consequence of including Protection Systems on step-down transformers that "look backwards" into the BES system as applicable to the standard. For instance, a distribution network fed from multiple transmission interconnections will have protective relaying (directional overcurrent most likely) to look backwards into the transmission system to trip the step-down transformer to prevent back-feed from the distribution network). This step-down transformer protection would be included in the new standard because it's purpose to the detect faults on the BES (event though the purpose of the protection is actually to protect overloading of the distribution and for worker safety on the BES); whereas the Y-W and Tri-State interpretation excludes that protection from the existing PRC-005-1 standard.

Response: Thank you for your comment. **The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.**		
Pepco Holdings Inc & Affiliates		Requirement 3 and the Supplementary Reference Document indicate that an entity should be held to its internal PSMP (especially for a time based program) even if the plan is more stringent than the NERC standard. This would be a deterrent for initiative and for excellence and punish utilities for going above the standards and performing best practices. It also tends to drive the industry to lowest common denominator practices. R3 and the accompanying Supplementary Reference Document should be appropriately revised to reflect that entities would only be held auditably accountable for the minimum requirements as stated in the standard and associated documents.
Response: Thank you for your comments. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
MRO's NERC Standards Review Forum		a. Section 4.2.5.4 includes station service transformers for generator facilities. As currently written, the section includes all the protection systems for station service transformers for generators that are a part of the BES. It states, "Protection Systems for generator-connected station service transformers for generators that are part of the BES." Generating facilities may have transfer schemes on the auxiliary transformer to transfer equipment to a reserve transformer instead of tripping the unit. These protection systems should not be included in the Facilities for PRC-005-2, since the BES is not affected. Recommend changing Section 4.2.5.4 to read, "Protection Systems that trip the generator for generator-connected station service transformers for generators that are a part of the BES."

		b. Data Retention, Section 1.3 (concerning R2 and R3) requires an entity to retain the two most recent performances of each distinct maintenance activity. This is an unreasonable requirement and does not enhance reliability. Recommend the data retention be changed to require only the most recent (past) test record. An example exists where an entity recently registered and tested all their relays prior to registering. They have one set of documentation and not two. PRC-005-2 allows testing intervals of up to 12 calendar years. If we are required to have the two most recent tests, we could conceivably have to retain a relay test record for 24 years. Recommend retention to be the most current record or all records since the last audit.
		c. Table 1-5 requires a maintenance activity to, "Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Recommend this be changed to, "Verify that each a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Or alternately, change the wording to, "Electrically operate each interrupting device every 6 years." While requiring each trip coil to operate the breaker sounds good in theory, practically it creates issues in the field and may create more problems than it solves. The trip coils are located in the panel at the breaker and aren't configured to test independently. Isolating one trip coil from the other may include "lifting a wire" that may not get landed properly when the test is complete. Then, how do you prove for a compliance audit that both trip coils were independently tested to trip the breaker? Using an actual event only tests one coil and we may not know which coil tripped the device. To be compliant, it isn't practical to be able to track a real-time fault clearing operation as suggested on page 67 of the Supplementary Reference document. First, we don't know which trip coil operated, then we have a "one off" device in the substation that must be tracked separately with a different testing cycle from the other devices in the substation. The standard should focus on ensuring the control circuitry is intact and trips the breaker without injecting additional, unneeded risk to the BES.

		d. General comment under Table 1-5: We do extensive testing of the control circuit during commissioning and after a modification to the circuit. Testing of the control circuitry on a periodic basis is not needed. The wear and tear on the equipment from functional testing and the potential risk of the testing itself may create more issues than the benefits received from doing the tests. The functional test injects significant opportunities for human performance errors during the test (technician trips the wrong device, differential relay opens all protective devices for a bus instead of a breaker, technician bumps another relay, screw driver falls into another device, etc.) and latent errors after the test (i.e., if a wire was lifted during the test, was it landed back in proper location, was the relay tripping function activated after the test was completed or was the relay left in test mode, etc.). Request the drafting team provide a basis for requiring the functional test. Are there documented instances where the control circuitry caused a significant event on the BES? Many utilities, monitor circuit breakers for operations. If a breaker hasn't operated for a defined period of time, we set up a maintenance activity to operate the breaker (possibly to include a timing test to ensure the breaker clears in the proper amount of cycles) - this ensures the operating linkages aren't bound and the breaker will operate. Misoperations are already monitored and reported through PRC-004. Does recent misoperation data or TADS data indicate that control circuitry/trip coils are a problem within the protection and control system? The current version of PRC-005 doesn't require functional tests. What is the basis for requiring additional compliance documentation (additional functional testing)? A possible alternative: only perform testing following modifications or major maintenance (like breaker change outs or panel modifications).
		e. Change the text of "Standard PRC-005-2 - Protection System Maintenance" Table 1-5 on page 19, Row 3, Column 2 to: "12 calendar years". 1) The maximum maintenance interval for "Electromechanical lockout and/or tripping devices which are directly in a trip path from the protective relay to the interrupting device trip coil" should be consistent with the "Unmonitored control circuit" interval which is 12 calendar years.2) In order to test the lockout relays, it may be necessary to take a bus outage (due to lack of redundancy and associated stability issues with delayed clearing). Increasing the frequency of bus outages (with associated lines or transformers) will also increase the amount of time that the BES is in a less intact system configuration. Increasing the time the BES is in a less intact system configuration also increases the probability of a low frequency, high impact event occurring. Therefore, the Maximum Maintenance Interval should be 12 years for lockout relays.

		f. In the background section of the implementation plan in item two it states "..it is unrealistic for those entities to be immediately in compliance with the new intervals." A recent compliance application notice (CAN-0012) indicated that auditors are requiring entities to include proof of compliance to maintenance intervals by providing the most recent and prior maintenance dates. Please provide clarity on CAN-0012 is applicable to PRC-005-2?
		g. The purpose statement of the standard seems to be inconsistent with the applicability section. To correct this it is suggested that the words "affecting the reliability" be removed from the purpose statement
		h. For consistency with the changes from 3 months to 4 months in the tables of the standard it is suggested that the second item in Table 1-4(b) be changed from 6 calendar months to 7 calendar months
		i. In the tables for dc Supply the term "unit-to-unit" is used along with "intercell" when referring to measurement of connection resistance. From the applicable IEEE standards (e.g. IEEE 450) the standard terminology seems to be "intercell". It is recommended that the "unit-to-unit" term be removed to avoid confusion regarding what is to be verified.
		j. The NSRF would like to extend our thanks to the drafting team. The 96 page Supplementary Reference document allows us to discuss these issues before the standard is approved, instead of as a potential violation later. Excellent job!

Response: Thank you for your comments.

a) The SDT has modified paragraph 4.2.5.4 as you suggest.

b) In order that a Compliance Monitor can be assured of compliance, the SDT believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted standard to establish this level of documentation. This seems to be consistent with the current practices of several Regional Entities.

c) The description of the configuration of the second trip coil on circuit breakers you have provided is not typical of the redundant approach taken by most entities. Typically, second trip coils are electrically isolated from the first trip coil and are often fed by a separately fused dc control circuit with different relay trip output, lockout and auxiliary tripping contacts utilized in each circuit. The SDT believes that it is important that redundant trip paths be maintained within the indicated interval, and the prescribed interval already considers the reliability benefits of redundant equipment.

d) The SDT believes that it is possible to manage the risks that you describe and that performance of these trip path verifications will be an overall benefit to the reliability of the BES.

e) The SDT believes that electromechanical lockout relays need periodic operation. As such, these devices are required to be exercised at the same 6 year interval required for electromechanical relays. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed. Performance-based maintenance is an option if you want to extend your intervals beyond 6 years. The SDT, however, has modified Table 1-5 to remove other auxiliary relays, etc, from this activity, and clarified that the verification of such.

f) The CAN cited applies to PRC-005-1, not PRC-005-2. The SDT intends that the Implementation plan associated with PRC-005-2 will govern compliance to PRC-005-2 during the transition to the new standard.

g) The purpose of the standard expresses the general intent of the standard, and is further clarified by the Applicability.

h) The SDT believes that the 6-month interval is appropriate for these activities.

i) The term “unit-to-unit” is used for the conductor utilized to connect one multi-celled battery jar to an adjacent multi-celled battery jar. The SDT does not believe this terminology causes wide spread confusion.

j) Thank you.

Arizona Public Service Company		While we are supportive of the changes the SDT has made, APS is concerned the draft Standard will not give entities the flexibility to continue to improve reliability based on changing industry norms and best practices. In addition, when technology changes for the better, industry will need the flexibility to optimize use of the new technology. Lastly, the more often protection equipment is taken out of service for testing, the more often the line is vulnerable. The balance between the correct amount of testing and correct amount of time the equipment is in the field and in service is an important consideration when assuring the reliability of the BES. APS suggests the general principles of the following two papers be applied to more equipment types than microprocessor relays with self test capabilities. 1) 'An Improved Model for Protective-System Reliability,' P.M. Anderson and S.K. Agrawal, Power Math Associates, Inc., IEEE Transactions on Reliability, Volume 41, No. 3, September 1992;2) 'Philosophies for Testing Protective Relays,' J.J. Kumm, et. al., Schweitzer Engineering Laboratory, Inc., 48th Annual Georgia Tech Protective Relaying Conference, May 1994.
Response: Thank you for your comments. FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. Wherever possible, the SDT has provided entities with the flexibility to utilize capabilities of emerging technologies by using condition-based maintenance where effective, and also by using performance-based maintenance should an entity wish to modify their intervals based on past performance.		
Southern Company Generation		1) For Table 1-1 and Table 3, consider adding "(internal to the relay)" to the microprocessor relay 6 calendar year maintenance activities to clarify that these maintenance activities are not related to items external to the relay).
Response: Thank you for your comments. Since the component type being addressed is the protective relay itself, it seems that the clarification you request is unnecessary.		

Tacoma Power		1. The implementation plan for R2 and R3 is unclear on whether each maintenance activity has its own implementation schedule. The implementation plan can also be interpreted to mean that the implementation schedule for a given protection system component is driven by the smallest maximum maintenance (allowable) interval. For example, for unmonitored communications systems, it is unclear whether all maintenance activities indicated in Table 1-2, including those corresponding to 6 calendar years, must be completed on all unmonitored communications systems by the first calendar quarter 15 months following applicable regulatory approval, or if this timeline only applies to the maintenance activity specified in Table 1-2 corresponding to a maximum maintenance interval of 4 calendar months.
		2. Assuming that there is a different implementation schedule for different maintenance activities for some protection system component types (namely station DC supply and communication systems), the middle bullet on page 1 of the implementation plan does not seem to consider that it may not be possible to identify whether some protection system components are completely being addressed by PRC-005-2 or the Program developed for the previous standards. In other words, during implementation, some maintenance activities for the same protection system component may be addressed by PRC-005-2, while other maintenance activities may be addressed by the Program developed for the previous standards.
		3. It is unclear whether control circuitry (trip paths) from protective relays that respond to mechanical quantities is included. This issue is addressed in the supplementary reference but is vague in the draft standard itself.
		4. This draft of PRC-005-2 requires the Protection System Maintenance Program (PSMP) to "include all applicable monitoring attributes and related maintenance activities" per the Tables and requires an entity to "implement and follow its PSMP." Under the draft standard, it is unclear whether an entity has to document in the PSMP and/or maintenance records how they accomplish(ed) the maintenance activities or simply to indicate that the maintenance activities are included and have been completed within the defined intervals. It is clear that entities are afforded some latitude in how they conduct the required maintenance activities. However, the level of detail required to document (1) how an entity chooses to perform the maintenance activities and (2) that applicable maintenance activities have been completed is not clear.

		5. In Table 1-2, there is a maintenance activity related to communication systems to "verify essential signals to and from other Protection System components." It is unclear if this statement is referring to control circuitry associated with the communication system end devices, end device input and output operation (as in Table 1-1 for protective relays), or something else. It is recommended that the requirement be to "verify operation of communication system inputs and outputs that are essential to proper functioning of the Protection System." This language is consistent with that used for protective relays in Table 1-1.
		6. Referring to Table 1-2, it is unclear whether an entity has the sole authority decide which 'performance criteria' are 'pertinent.' Additionally, it is unclear if an entity must document the 'communications technology applied' and the associated 'performance criteria' in its PSMP.
		7. In Table 1-4, it is unclear if there is a distinction between the terms 'resistance' and 'ohmic values.' If there is a distinction, then this distinction should be clarified.
		8. In Table 1-4, it is unclear if there is a distinction between the terms 'battery terminal connection resistance' and 'unit-to-unit connection resistance.' If there is a distinction, then this distinction should be clarified.
		9. In Table 1-4, replace the term 'resistance' with 'impedance.'
		10. Recommend that the 6 calendar month interval in Table 1-4(b) be lengthened to 18 calendar months to be more consistent with similar maintenance activities for other battery types. At minimum, lengthen the interval to at least 7 calendar months in a similar way that 3 calendar months was lengthened to 4 calendar months for other maintenance activities.

		11. Referring to Table 1-5, no periodic maintenance is required for “control circuitry whose continuity and energization or ability to operate are monitored and alarmed.” It is unclear whether or not it is acceptable to verify DC voltage at the actuating device trip terminals at least once every 12 calendar years for “unmonitored control circuitry associated with protective functions.” It is recommended that periodically verifying DC voltage in this manner be an acceptable means of accomplishing the maintenance activity identified in Table 1-5 for unmonitored control circuitry associated with protective functions.
		12. Referring to 4.2. Facilities of the draft standard, it is unclear whether protection systems for transformers that step down from over 100kV to below 15kV are applicable to the standard. Even if there are normally-open distribution feeder ties for purposes of transferring load in a make-before-break fashion, these transformers are generally not considered BES elements.
		13. Referring to 4.2.5 of the draft standard, it is unclear whether protection for generator excitation systems are applicable to the standard.
		14. It is unclear whether external timing relays (e.g., Zone 2) are considered control circuitry components (like lockout and auxiliary relays) or protective relay components.

Response:	**Thank you for your comments.**
	1. The SDT agrees with your observation and has changed the relevant parts of the Implementation plan to clarify that they apply to the maintenance activities for the relevant maintenance intervals.
	2. The SDT agrees with your observation and revised the Implementation plan to clarify.

	3. The trip paths from protective relays that respond to mechanical quantities and are intended to detect faults are a part of the Protection System control circuitry. The sensing elements are omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocols for these sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1, consistent with the SAR for Project 2007-17, and the SDT understands this to be consistent with the position of FERC staff. Note that trip signals from devices sensing mechanical parameters not directly indicative of an electrical fault need not be tested per this standard.
	4. The SDT has removed parts 1.1 and 1.3 from Requirement R1, addressing part of your comment. The SDT agrees that PRC-005-2 allows some leeway in how an entity fulfills the testing requirements of the standard. Section 15 of the Supplementary Reference and FAQ document provides numerous examples of possible testing techniques for the various component types making up a Protection System. An entity's PSMP should clearly define how the testing requirements of the standard are fulfilled. The Measures for each requirement, as well as Section 15.8 of the Supplementary Reference and FAQ document, provide some examples of possible compliance documentation for completion of testing.
	5. The SDT agrees with your suggestion and has changed the standard accordingly.
	6. The entity has the authority to establish its own acceptable performance criteria. This criteria does not need to be in the PSMP, but should reside somewhere within the maintenance documentation.
	7. As utilized on Table 1-4, the term "ohmic value" is a generic reference to the measurement of a battery cell or units ability to pass current flow. This may be done using conductance, resistance or impedance measurements; the various battery test equipment manufacturers use different measurement methods and the term "ohmic value" is meant to be technology neutral. See FAQ on page 78 of the Supplementary Reference and FAQ document. The term "resistance" as used in Table 1-4 refers specifically to the dc resistance of the battery terminal connections and the battery intercell/inter-unit physical connectors. See related FAQ on pages 74-75 of the Supplementary Reference and FAQ document.

	8. Battery terminal connection resistance is a measurement of the resistance of a connection at a battery terminal. Battery intercell or unit-to-unit connection resistance is a measurement of the resistance of the external conductor interconnecting two adjacent battery cells or two adjacent multi-cell battery units. The SDT believes these are common battery maintenance terms used throughout the industry.
	9. The SDT disagrees and believes that resistance as used in Table 1-4 is the appropriate term for the parameters to be measured and is consistent with standard battery system maintenance terminology.
	10. The SDT disagrees with your recommendation to standardize maintenance intervals between different battery types that have distinctly different failure mechanisms. See related FAQ on pages 80-81 of the Supplementary Reference and FAQ document for further discussion of requirements for ohmic measurements of VRLA batteries. Concerning your recommendation to allow for 7 calendar months, the SDT believes that the six-month interval specified is appropriate.
	11. The SDT has modified this specific portion of the Table, and believes that the modifications address your concern. Please see Section 15.3 of the Supplementary Reference and FAQ document for a discussion of this topic.
	12. The standard does not include the Protection Systems for transformers that step down from over 100kV to below 15kV if these transformers are not BES elements. If Protection Systems are installed for purposes of detecting Faults on BES elements, these Protection Systems are included.
	13. Paragraph 4.2.5.1 indicates that the excitation system protection system would only be in scope if the excitation system generates signals that trip the generator output breaker either directly or via lockout or auxiliary tripping relays.
	14. As timing is critical to proper Protection System function, timers are considered protective relays.

Progress Energy		1. Standard, Table 1-4(a), second sentence under Component Attributes, should state "Protection System Station dc supply for non-BES interrupting devices for SPS or non-distributed UFLS and UVLS systems are excluded...." As written, the statement does not include the phrase "UFLS and." I believe it should. 2. Supplemental, Section 13, 2nd paragraph, first sentence should state: "...device match the minimum requirements listed in Tables 1 and 3."

Response: Thank you for your comments.

1. **The SDT agrees. Table 1-4(a) has been modified as you suggest; this text has been relocated to the header of the table.**
2. **The SDT agrees and has modified the Supplementary Reference and FAQ document as you suggest.**

Western Area Power Administration		Comment 1:Western Area Power Administration does not agree with penalizing utilities for implementing maintenance programs that exceed the requirements defined in the NERC Standard PRC-005-2 maintenance tables. Although the intent of the language in the Supplementary Reference and FAQ document may have been to allow evolving maintenance programs to include condition-based and performance based maintenance in their programs, penalizing utilities with more stringent programs will more likely provide a disincentive for program development. Utilities will discontinue any additional maintenance activities that could put them at risk for non-compliance. This will cause maintenance programs to stagnate and new maintenance ideas to improve system reliability to not be implemented. It is the opinion of the Western Area Power Administration that the following text should be removed from the Supplementary Reference and FAQ document and entities should be audited to the minimum requirement of the standard regardless of their individual programs. Recommendation: Remove the following text from the Supplementary Reference & FAQ document:1. Page 26 - The bullet “If your PSMP (plan) requires more activities then you must perform and document to this higher standard.” 2. Page 27 - The bullet “If your PSMP (plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard.” 3. Page 27 - The paragraph “It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-2. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-2, most notable of which is an entity using performance based maintenance methodology. (Another reason for having a more stringent plan than is required could be a regional entity could have more stringent requirements.) Regardless of the rationale behind an entity’s more stringent plan, it is incumbent upon them to perform the activities, and perform them at the stated intervals, of the entity’s PSMP. A quality PSMP will help assure system reliability and adhering to any given PSMP should be the goal.” Revise R3 of PRC-005-2 and add statement to the Supplementary Reference & FAQ document.1. R3: Each Transmission Owner, Generator Owner and Distribution Provider shall implement and follow its PSMP plan within the prescribed intervals of Tables 1, 2 and 3. and correct any unresolved maintenance issues.2. FAQ: Any utility maintaining Protection System equipment that exceeds the requirements and tables because of historical testing data and/or failure documentation should not be held non-compliant or penalized for not meeting its PSMP, as long as they do not exceed the maximum allowable intervals or meet the minimum maintenance activities of the standard.

		Comment 2:R3 of PRC-005-2 states "Each Transmission Owner, Generator Owner, and Distribution Provider shall implement and follow its PSMP and initiate resolution of any unresolved maintenance issues." The Western Area Power Administration would like more clarification on potential data request for requirement R3 of PRC-005-2. Because the requirement uses the term initiates resolution, the entity could make the assumption that providing just a list of maintenance request for unresolved maintenance issues will serve to prove compliance. Although it would seem implied that whatever method used to initiate resolution would lead to some type of corrective maintenance, the requirement does not make that absolutely clear. To ensure the maintenance practices are meeting the intent of the requirement, the requirement needs to clarify the expectations for completing corrective maintenance that was initiated to resolve maintenance issues. Recommendation: Add additional clarification to Supplementary Reference & FAQ document to further clarify expectation for this requirement.

Response: Thank you for your comments.

1. **The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.**
2. **Additional clarification has been added to the Supplementary Reference and FAQ document. Additional examples have also been added to the Measure for this Requirement.**

PacifiCorp		1. The data retention requirement for producing evidence that the entity performed maintenance for the 2 most recent maintenance intervals is excessive. As an example, if a registered entity's maintenance/test interval is 12 years, such entity may be required to keep records for up to 35 years. PacifiCorp recommends a revision to the data retention requirement to provide for either a maximum retention period of 10 years or, in cases in which the interval exceeds 10 years, the most recent maintenance/test cycle only. 2. The requirement to identify all PTs is very onerous and not needed to verify maintenance compliance and therefore serves a limited reliability benefit. PacifiCorp believes that, as long as a registered entity can demonstrate that it can verify that all CTs/PTs providing input into a Protection System have been tested and maintained according to its established procedures, then a separate and independent requirement to maintain a list of these devices is not necessary. As an example, if an entity performed their protection system maintenance on a "scheme" basis, and as part of that maintenance documentation identified all CT's and PT's providing input into the scheme and verified their accuracy, then having a "master list" would provide no benefit. A list of all CT's associated with one device such as a circuit breaker would have little value in this case as these CT's may provide input into multiple relay schemes and would not be maintained on an individual circuit breaker basis.

Response: Thank you for your comments.

1. **In order that a Compliance Monitor can be assured of compliance, the SDT believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted standard to establish this level of documentation. This seems to be consistent with the current practices of several Regional Entities.**
2. **The SDT does not believe the current standard contains a "separate and independent requirement to maintain a list of these devices". As your comment correctly indicates, if an entity can provide evidence that the inputs from all CTs and PTs are accurately being received by the associated relays for in scope Protection Systems, this is acceptable. It is up to the entity to best determine how to track this – whether by a "master list" of CTs and/or PTs, on a "scheme" basis, by physical location of the instrument transformer, or some other effective tracking method.**

Saft America, Inc.		Saft Comments on NERC Standard PRC-005-2 - Protection System Maintenance - Please find herein Saft's comments to NERC PRC-005-2 regarding ohmic testing of Nickel-Cadmium (NiCad) batteries. As drafted, the proposed NERC Standard PRC-005-2 will lead to the removal of high quality, reliable NiCad battery power units from Protection Systems, which is counter to the NERC stated purpose of PRC-005-2, which is to 'document and implement programs for the maintenance of all Protection Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.' There is broad consensus within the battery industry that ohmic testing of Valve Regulated Lead-Acid (VRLA) batteries provides a means for trending the condition of the battery over time. Such a consensus does not exist for Vented Lead-Acid (VLA) batteries, because ohmic measurements are more difficult to trend, thereby providing a go/no-go assessment of the battery's availability at that precise moment in time, rather than a measure of VLA battery condition. Ohmic testing of NiCad batteries provides a similar go/no-go assessment to ohmic testing of VLA batteries. As with VLA batteries, ohmic testing of NiCad batteries does not provide meaningful trending information, but rather provides a status update of battery condition at a specific moment in time. Due to the similar information provided by ohmic testing of VLA and NiCad batteries, Saft recommends that ohmic testing of NiCad batteries be included under the Maintenance Activities for NiCad batteries. Specifically, Saft recommends that NERC add the following language to the Maintenance Activities column in Table 1-4(d), 'Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline', at a maximum maintenance interval of 18 months, as in the requirement for VLA batteries noted in Table 1-4(a).

Response: Thank you for your comments.

The SDT disagrees. The SDT is aware of studies that indicate a correlation between ohmic measurements and battery condition (or remaining life) for VLA and VRLA batteries when trended against a baseline ohmic measurement taken when the battery was new. These same studies concluded no such correlation exists for NiCad batteries. We are unaware of any published studies that conclude otherwise for NiCad batteries. The standard does not favor one technology over another but simply allows flexibility in testing techniques when the attributes of a technology allow for technically justifiable application of that flexibility and achieve the objective of the standard.

Nebraska Public Power District		a. Section 4.2.5.4 includes station service transformers for generator facilities. As currently written, the section includes all the protection systems for station service transformers for generators that are a part of the BES. It states, "Protection Systems for generator-connected station service transformers for generators that are part of the BES." Generating facilities may have transfer schemes on the auxiliary transformer to transfer equipment to a reserve transformer instead of tripping the unit. These protection systems should not be included in the Facilities for PRC-005-2, since the BES is not affected. Recommend changing Section 4.2.5.4 to read, "Protection Systems that trip the generator for generator-connected station service transformers for generators that are a part of the BES."
		b. Section 1.3 requires an entity to retain the two most recent performances of each distinct maintenance activity. This is an unreasonable requirement and does not enhance reliability. Recommend the data retention be changed to require only the most recent test record. An audit should be focused on the present day and not in the past. Is an entity compliant today and not can we find a way to issue a fine for something in the past? An example exists where an entity recently registered and tested all their relays prior to registering. They have one set of documentation and not two. Why should they be forced into testing again and incurring additional expense for customers only to have two tests available for an auditor? This does not enhance reliability. PRC-005-2 allows testing intervals of up to 12 calendar years. If we are required to have the two most recent tests, we could conceivably have to retain a relay test record for 24 years! Hypothetically, if we have a test record from ten years ago, but we don't have the record from 24 years ago, how does that adversely affect the reliability of the BES today? The standard should focus on - Are we compliant today?

		c. Table 1-5 requires a maintenance activity to, "Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Recommend this be changed to, "Verify that a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Or alternately, change the wording to, "Electrically operate each interrupting device every 6 years." While requiring each trip coil to operate the breaker sounds good in theory, practically it creates issues in the field and may create more problems than it solves. The trip coils are located in the panel at the breaker and aren't configured to test independently. Isolating one trip coil from the other may include "lifting a wire" that may not get landed properly when the test is complete. Then, how do you prove for a compliance audit that both trip coils were independently tested to trip the breaker? Using an actual event only tests one coil and we may not know which coil tripped the device. To be compliant, it isn't practical to be able to track a real-time fault clearing operation as suggested on page 67 of the Supplementary Reference document. First, we don't know which trip coil operated, then we have a "one off" device in the substation that must be tracked separately with a different testing cycle from the other devices in the substation - this is a recipe for a compliance violation. The standard should focus on ensuring the control circuitry is intact and trips the breaker without injecting additional, unneeded risk to the BES.

		d. General comment under Table 1-5: We do extensive testing of the control circuit during commissioning and after a modification to the circuit. Testing of the control circuitry on a periodic basis is not needed. The wear and tear on the equipment from functional testing and the potential risk of the testing itself may create more issues than the benefits received from doing the tests. The functional test injects significant opportunities for human performance errors during the test (technician trips the wrong device, differential relay opens all protective devices for a bus instead of a breaker, technician bumps another relay, screw driver falls into another device, etc.) and latent errors after the test (i.e., if a wire was lifted during the test, was it landed back in proper location, was the relay tripping function activated after the test was completed or was the relay left in test mode, etc.). Request the drafting team provide a basis for requiring the functional test. Are there documented instances where the control circuitry caused a significant event on the BES? Many utilities, including us, monitor our circuit breakers for operations. If a breaker hasn't operated for a defined period of time, we set up a maintenance activity to operate the breaker (possibly to include a timing test to ensure the breaker clears in the proper amount of cycles) - this ensures the operating linkages aren't bound and the breaker will operate. We have many maintenance activities performed on devices for the BES that do not require a NERC standard. If a utility chooses not to perform best practice maintenance, customers will experience more frequent and longer outages. The utility will receive customer feedback on outages which should translate into the utility increasing its maintenance. In other words, we don't have to include a functional test as a NERC requirement. Misoperations are already monitored and reported through PRC-004. Does recent misoperation data or TADS data indicate that control circuitry/trip coils are a problem within the protection and control system? The current version of PRC-005 doesn't require functional tests. What is the basis for requiring additional compliance documentation (additional functional testing)? A possible alternative: only perform testing following modifications or major maintenance (like breaker change outs or panel modifications).

		e. Recommend NERC provide training specifically on how to audit PRC-005-2 to auditors in all eight Regional Entities. PRC-005 is the most violated standard since enforcement began on June 18, 2007. This is an excellent opportunity for NERC to get all eight regions on the same page for what to audit. NERC provides training on standard auditing guidelines and sample selection, but doesn't provide training on how to audit specific standards. RSAW's and CAN's have been an attempt to get consistency across the regions, but differences are still obvious. NERC is in the perfect position to observe potential violations (PV) from an auditor and as a PV is written that goes beyond the standard or is not in accordance with the initial training; NERC can dismiss the PV and retrain the auditor. Auditors aren't perfect, nor are any of us. Training is a basic tool for the auditor to perform their job properly.

Response: Thank you for your comments

a) The SDT has modified paragraph 4.2.5.4 as you suggest.

b) In order that a Compliance Monitor can be assured of compliance, the SDT believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted standard to establish this level of documentation. This seems to be consistent with the current practices of several Regional Entities.

c) The description of the configuration of the second trip coil on circuit breakers you have provided is not typical of the redundant approach taken by most entities. Typically, second trip coils are electrically isolated from the first trip coil and are often fed by a separately fused dc control circuit with different relay trip output, lockout and auxiliary tripping contacts utilized in each circuit. The SDT believes that it is important that redundant trip paths be maintained within the indicated interval, and the prescribed interval already considers the reliability benefits of redundant equipment.

d) The SDT believes that it is possible to manage the risks that you describe and that performance of these trip path verifications will be an overall benefit to the reliability of the BES.

e) The SDT will forward this comment to NERC Compliance for their consideration.

Exelon		
Texas		(1) General - defined terms need to be capitalized throughout this standard.

Reliability Entity		(2) Requirement R3 only addresses initiation of resolution to any Unresolved Maintenance Issues. Requirement R3 should require completion of corrective action to deal with Unresolved Maintenance Issues within a reasonable timeframe.
		(3) Section 1.3, Data Retention, should require each entity to keep all versions of its PSMP that were in effect since its last compliance audit, in order to demonstrate compliance at all relevant times (not just the current version).
		(4) In the Severe VSL for R2, add “Annually” to the second bullet under part 5.
		5) The VSLs for R3 should contain a time frame (annual?). The second part of these VSLs should refer to initiation and completion of resolution of Unresolved Maintenance Issues. (See comment on Requirement R3 above.)
		(6) Consider making the R3 VSLs based on a percent of the number of maintenance activities required by the PSMP in a stated time period, rather than on a percent of the total number of Components.
		(7) There is no maintenance activity listed to verify that protection system component settings meet the design intent of the protection system. In other words, there is no required activity to confirm that the “specified” settings are correct and appropriate. This introduces a potential reliability gap into the Protection System maintenance program.
		(8) In Table 1-1, the term “acceptable measurement of power system input values” is somewhat vague. A tolerance value or reference to industry standards should be provided.
		(9) In Table 1-3, the activity should include verifying that the current and voltage signal values are within design tolerances, not just that signal values are present.
		(10) In Table 1-4(a) Component Attributes - the reference to UFLS systems is missing in the exclusion that refers to UVLS systems. (UFLS is included in Tables 1-4(b) through 1-4(d).)

		(11) In table 1-4(f), there should be a reference to "alarming" in addition to "monitoring" in the first cell of the next-to-last row
		(12) In table 1-4(f), why is the last row limited to VRLA station batteries? Should the same exclusion apply to VLA batteries?
		(13) In Table 1-5, a "12 calendar year" interval is too long for "Unmonitored control circuitry associated with SPS" and "Unmonitored control circuitry associated with protective functions." We suggest this be changed to 6 years. Similar unmonitored attributes related to battery maintenance have a 6 calendar year interval.
		(14) In Table 2, the phrase "location where corrective action can be initiated" is unclear, and we suggest that a more definitive description be used. Also, why is the word "DETECTION" in all-caps?
		(15) In Table 3, the maintenance activity should include verifying that Protection System Component settings meet the design intent of the Protection System. For example, any reclosing function should be disabled on UFLS and UVLS relay systems.
		(16) In Table 3, In Table 1-1, the term "acceptable measurement of power system input values" is somewhat vague. A tolerance value or reference to industry standards should be provided.
		(17) The Implementation Plan is overly long and complicated. Entities (including Regional Entities) will have to track and apply multiple versions of this standard for 14 years. It would be preferable to have a much shorter implementation plan, so that only one version of the standard will be applicable, recognizing that for some Components no action will be required under the standard for a number of years.

Response:	**Thank you for your comments.**
	1. The SDT will attempt to properly capitalize defined terms throughout the standard.

	2. The SDT specifically chose the phrase "initiate resolution" because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve. For example, a problem might be identified on a VRLA battery during a 6 month check. In instances such as one that requiring battery replacement as part of the long term resolution, it is highly unlikely that the battery could be replaced in time to meet the 6 calendar month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely but concludes it would be impossible to postulate all possible remediation projects and therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues or what documentation might be sufficient to provide proof that effective corrective action has been initiated. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues.
	3. The SDT agrees with your observation and has modified the data retention requirements accordingly.
	4. The SDT agrees with your observation and has modified VSL for Requirement R2 accordingly.
	5. The percentages relate to the number of violations of the respective requirement reported within the compliance monitoring period relative to the number of components within that component type. PRC-005-2 only requires the entity "… initiate resolution" of the issue found. The SDT recognizes that performance of the activities necessary to resolve an issue are entirely dependent upon the circumstances surrounding that issue and, consequently, will require varying amounts of resources and time to complete the process. It is for this reason the SDT crafted the requirement to only require initiation of the process.
	6. The SDT disagrees. The entity must complete all required activities on any specific component in order to be compliant, regardless of the number of activities scheduled for that component.
	7. The SDT believes that adequacy of settings is more properly a design issue and should not be included in a maintenance standard.

	8. The SDT believes it is more appropriate for entities themselves to establish acceptance criteria that meet the performance requirements necessary for the proper operation of their Protection Systems.
	9. The action, "verify" is specified within the PSMP definition as "Determine that the component is functioning correctly." Therefore, the SDT believes that the suggested change is unnecessary.
	10. The SDT agrees. Table 1-4(a) has been modified as you suggest. The modified text has been moved to the header of the tables.
	11. The SDT agrees. Table 1-4(f) has been modified as you suggest.
	12. The SDT agrees. Table 1-4(f) has been modified as you suggest.
	13. The SDT disagrees and believes that the 12 year requirement for SPS's is in alignment with the Table 1-5 row 4 requirement for testing of unmonitored trip paths for control circuitry with protective function in other Protection Systems.
	14. Based on a lack of other comments received on this topic, the SDT believes that this description has sufficient clarity. The word "detection" on Table 2 has been corrected to lower case font.
	15. The first row of Table 3 requires that settings be verified to be as specified. The SDT believes this to be a proper maintenance function but that the determination of the adequacy of settings (or, for that matter, design criteria) is more properly a design issue and should not be included in a maintenance standard.
	16. The SDT believes it is more appropriate for entities themselves to establish acceptance criteria that meet the performance requirements necessary for the proper operation of their Protection Systems.

	17. The SDT disagrees. It is not practical for all entities to rapidly transition all of their protection systems to the new program, especially with some component types on maintenance intervals of up to 12 years. Nonetheless, all in scope Protection Systems must either be being maintained by either a PRC-005-1 program or a PRC-005-2 program. The SDT believes the graded approach mapped out in the Implementation plan is practical. Finally, if in order to lessen the complexity of documentation requirements, an entity wishes to implement PRC-005-2 on a more rapid rate than laid out in the Implementation plan, they are free to do so.	
Central Lincoln		We are concerned about what exactly “initiate resolution” means in R3. We foresee this being a potential area of disagreement between registrants and CEAs when a registrant believes an open work order suffices and the CEA wants to see schedules or purchase orders. Neither M3 nor the FAQs address this.
Response: Thank you for your comment. The SDT has clarified the intent of the requirement to initiate resolution of Unresolved Maintenance Issues by including it separately as Requirement R5 and revising the language such that the responsible entity must demonstrate its efforts to correct Unresolved Maintenance Issues because of the concern that many more complex Unresolved Maintenance Issues might require greater than the remaining maintenance interval to resolve. For example, a problem might be identified on a VRLA battery during a 6 month check. In instances such as one that requiring battery replacement as part of the long term resolution, it is highly unlikely that the battery could be replaced in time to meet the 6 calendar month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely but concludes it would be impossible to postulate all possible remediation projects and therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues or what documentation might be sufficient to provide proof that an entity is correcting these issues.		
Dynegy Inc.		For Facilities listed under 4.2, are Reserve Auxiliary Transformers supposed to be included?

Response: Thank you for your comment.

No, Reserve Auxiliary Transformers or system connected station service transformers were intentionally removed from the Applicability in a previous draft. Generator-connected station service transformers are often connected to the generator bus directly without an interposing breaker; thus, the Protection Systems on these transformers will trip the generator as discussed in 4.2.5.1. and are thus included. Reserve auxiliary or system connected station service transformers Protection Systems will not directly result in the trip of a generator and as such are omitted from the Applicability of the standard.

American Electric Power		1. As it stands, if an entity adopts a more stringent maintenance program but fails to meet it, that entity could be found non-compliant despite continuing to abide by the minimum requirements of the standard itself. Entities should have the ability, if they so choose, to include additional maintenance activities or more stringent intervals than specified within the standard without concern of penalty in the event they are unable to accomplish them. In short, entities should only be audited against the requirements stated within the standard. Table 1-3 of the standard lists the minimum required maintenance activities for voltage and current sensing devices as "Verify that current and voltage signal values are provided to the protective relay." 2. Consistent with Table 1-3, Section 15.2.1 of the Supplementary Reference states that an entity "...must verify that the protective relay is receiving the expected values from the voltage and current sensing devices..." The Supplementary Reference further offers examples of how this requirement may be satisfied with most examples referencing the need to verify the signal at each relay in the circuit. We recognize the need to verify a voltage signal at each protective relay, as these devices are wired in parallel and an open circuit at one location may not impact the other devices on the circuit. However, we do not agree that there is a need to verify a current signal at each protective relay. Current devices are wired in series, and an open circuit at any location will impact all other devices on the circuit. For this reason, a single measurement of the current circuit is sufficient. We recommend updating Table 1-3 and the supplementary reference to account for the different physical characteristics of voltage and current circuits. 3. This standard encompasses a very broad range of component types and functionality across broad segments of the BES. The proposed VSLs and VRFs place the same level of severity or priority on facilities that serve local load with that of an EHV facility. The percentages indicated in the VSLs seem to be too strict based upon the vast quantity of elements in scope and broad range of application. Other standards have applicability for certain thresholds of voltage levels, etc. Why not this standard as well?

Response: Thank you for your comments.

1. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.
2. An open circuit is not the only failure mechanism for a CT secondary circuit. Grounded CT secondary wiring can result in situation where accurate current is present in the part of the secondary circuit upstream of the ground but current would be shunted to ground and might not pass through devices downstream of the ground. Entities should not interpret PRC-005-2 as specifying "how" to test but rather that PRC-005-2 only specifies "what" to test. Entities are free to determine creative ways to fulfill requirements.
3. VSLs characterize "how bad did you miss a requirement", rather than on the impact to the BES. The percentages indicated in the VSLs follow demarcation guidelines given by NERC to Standard Drafting Teams. With the magnitude of the total number of Protection System components for many entities likely to be very large, exceeding 5% of that total equates to failing to perform maintenance and testing on a (potentially) large number of components, and should be reflected by a Severe VSL. The SDT further believes that this standard should be applied uniformly to the applicable facilities, rather than stratifying it to reflect different system voltages.

Lincoln Electric System		In reference to the zero tolerance policy evident within PRC-005-2, LES offers the following suggestion: Set up an annual review of a random set sample (20% for example) of Protection System equipment to self-verify compliance. If issues arise, allow the entity the opportunity to correct the issue, make the necessary procedural and/or documentation adjustments and not be considered non-compliant. The idea is to allow entities the opportunity to continually improve their practices and procedures; in essence, allow them to show they are attempting to follow a "culture of compliance". If habitual problems arise, then non-compliance will be evident. One example that justifies this approach is software glitches or improper programming. As more and more systems become automated, scheduling of maintenance will be done automatically through various types of software. If a program has even one attribute set incorrectly, it could not function as intended and would potentially set up incorrect intervals for maintenance and testing. It was not intended this way by the entity and they are not intentionally disregarding the standards, but could nevertheless be put in a situation where a maintenance interval is missed. An annual review would catch things like this and allow an entity to continuously improve their program without self-reporting. This concept is expanded from a current draft version of several CIP standards; therefore, it is being at least considered by other drafting teams.
Response: Thank you for your comments. **The NERC criteria for VSLs do not permit any level of non-performance without being in violation. The graded approach of the VSL for Requirement R3 provides for an escalating degree of severity for increasing degrees of non-compliance.**		
NIPSCO		The new standard itself, the implementation plan and supplemental reference/FAQ makes up more than 100 pages of material. Granted that several standards are being combined here, still it is simply too involved to monitor. And there is still not enough detail in the standard leaving items which are ambiguous and open to interpretation, and therefore open to fines. In order to remove such interpretation, maintenance documentation will need to be precise and extensive. This will necessitate more and more staff to control and validate data. Adding staff is great but it does not seem to ensure that there is increased reliability.

Response: Thank you for your comment. **FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that may be consistently monitored for compliance.**		
Entergy Services		We understand and disagree with the SDT position on the following recommendation. We do not agree with proposed Section 4.2.1 applicability since it captures only a portion of the previously approved applicability Interpretation (PRC-005-1a) which was developed specifically for PRC-005-1. We suggest the draft standard be revised to conform to the wording in the Interpretation: "Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.) and trips an interrupting device that interrupts current supplied directly from the BES Elements."
Response: Thank you for your comment. **The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.**		

Independent Electricity System Operator		The IESO disagrees with the concept that auditors use the standards as minimum requirements and evaluate compliance based on a registered entity's own governance. We believe that the entity could be found non-compliant with Requirement R3 if they fail to follow the internal maintenance intervals established in their PSMP, even though actual maintenance intervals are no less frequent than the prescribed maximum intervals established in the draft standard. The potential for such a finding will discourage conscientious entities from setting higher internal targets for their planned maintenance and promote compliance with only the minimum requirements of the standard. We therefore propose the following revision to Requirement R3:R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement and follow its PSMP and initiate resolution of any unresolved maintenance issues. In the case of time-based maintenance programs, each Transmission Owner, Generator Owner, and Distribution Provider is permitted to deviate from its PSMP provided that actual maintenance intervals do not exceed those specified in Tables 1-1 through 1-5, Table 2 and Table 3. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
Response: Thank you for your comments. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		

Liberty Electric Power LLC		With the development and publication of maximum maintenance and testing intervals (the Tables), there is no longer a reliability need for a RE to identify the associated maintenance intervals for Protection System Components. Further, REs who wish to perform these activities in shorter intervals than those allowed by the standard (See Supplementary Reference, page 27,"If your PSMP (plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard.")As noted in Question 5, if the entity completes all activities within the maximum interval allowed by the standard, there can be no reliability concern; if there is a reliability issue, then the table interval is incorrect. I would suggest the following changes.1. Change R1.2 to read "Identify any Protection System component where the RE is using a performance based maintenance interval. No batteries associated with the station DC supply component type of Protection System shall be included in a performance based system".2. Change R1.3 to read "The intervals for time-based programs are established in Table 1-1 through 1-5, Table 2, and Table 3".3. Change M1 to add the phrase "for performance-based components" after the words "maintenance intervals".4. In M1, replace the words "the type of maintenance program applied (time-based, performance based, or a combination of these maintenance methods)' with the words "the identification of any protection system components using performance based intervals".
Response Thank you for your comments. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		

Ameren		(1)Measure M3 on page 5 should only apply to 99.5% of the components. Please revise to state: "Each ... shall have evidence that it has implemented the Protection System Maintenance Program for 99.5% of its components and initiated...." PRC-005-2 unrealistically mandates perfection without providing technical justification. A basic premise of engineering is to allow for reasonable tolerances, even Six Sigma allows for defects. Requiring perfection may well harm reliability by distracting valuable resources from higher priority duties concerning the Protection System. We are not asking for the VSL to be changed. No one is perfect and it is impractical to imply perfection is achievable. The consequence of a very small number of components having a missed or late maintenance activity is insignificant to BES reliability. Our proposed reasonable tolerance sets an appropriate level of performance expectation. We disagree with the notion that this is "non-performance". (2) An alternate approach regarding the unrealistic perfection of M3 is to correctly recognize that the protection of the primary BES is the objective. Most Protection Systems are redundant by design and the entity needs to be afforded the opportunity to show that a redundant component met the PSMP thereby providing the required protection. The entity should be allowed a reasonable time frame of one calendar increment to maintain the component in question. Our concern stems from the tens of thousands of components in a PSMP, and the reality that rarely but occasionally a data base error or outage scheduling issue may result in a very small number component exceeding their maximum interval. As long as the entity can show that BES protection was sustained and maintains the component quickly (e.g. within one calendar month of discovery), BES reliability has been maintained. (3) Now that FERC has approved the Project 2009-17 Interpretation, please acknowledge more directly in the Supplement that the 'transmission Protection System' that is now approved. NERC interprets "transmission Protection System," as it appears in Requirements R1 and R3 of PRC-004-1 and Requirements R1 and R2 of PRC-005-1, to mean "any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directly from the BES."

Response: Thank you for your comments.

1. The NERC criteria for VSLs do not permit any level of non-performance without being in violation. The graded approach of the VSL for Requirement R3 provides for an escalating degree of severity for increasing degrees of non-compliance.
2. Regarding redundancy, the SDT believes that it is important that redundant components be maintained within the indicated interval, and the prescribed interval already considers the reliability benefits of redundant equipment. It should be noted that misoperations not only occur for failure to operate for valid faults but also operation of a protection system for an invalid, non-fault condition. It is important that both components be maintained within the specified intervals to help preclude this second type of misooperation – e.g., over tripping of relays.
3. The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.

Northeast Utilities		1. The definition of "Component" in PRC-005-2 Draft 1, states "Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component." However, in Section 15.2 of Supplementary Reference & FAQ it states: "The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample." Please consider reconciling these two sections (definition of "Component" and Section 15.2) to allow the entity to consider a relay as the single component versus the voltage and current sensing devices, and pursuant with Section 15.2 perform the voltage and current checks to the inventoried relays. This approach will ensure that the CT and PT check to each relay is performed. Section 15.2 of Supplementary Reference & FAQ states in the second paragraph "The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample." Please consider revising the last bullet in Section 15.2, paragraph 3 from "Any other method that provide documentation that the expected transformer values as applied to the inputs to the protective relays are acceptable" to "Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample." 2. As shown (see Figure A-2) and discussed in Appendix A of Supplementary Reference & FAQ list, there are four elements that are not verified. Following the identification of the four elements that are not verified, a practical solution is provided for testing methods on three of the four elements. Please provide a practical solution for the fourth element.

Response: Thank you for your comments.

1. **The SDT does not believe a discrepancy exists. CTs and PTs or other current and voltage sensing devices are indeed Protection System Components. Section 15.2 of the Supplementary Reference and FAQ document is describing a maintenance activity that is to be performed to validate proper function of that Component type. The Supplementary Reference and FAQ document has been revised to clarify.**
2. **Appendix A to the Supplementary Reference and FAQ document (with the imbedded figures) is intended to provide an example of the application of monitoring to minimize maintenance activities and maximize maintenance intervals, but is not intended to be a comprehensive treatise of the subject.**

MidAmerican Energy Company		1. The following comment was submitted in the last comment period: In the background section of the implementation plan in item two it states "..it is unrealistic for those entities to be immediately in compliance with the new intervals." Recent compliance application notices indicate that auditors are requiring entities to include proof of compliance to maintenance intervals by providing the most recent and prior maintenance dates. The implementation document could be improved by providing clarity to what is expected with regard to when an entity is expected to provide evidence of maintenance interval compliance given the quoted item above. As an example in the section the implementation plan for a 6 year interval item it states: " The entity shall be at least 30% compliant on the first day of the first calendar quarter 3 years following applicable regulatory approval.." In keeping with the previously quoted "reasonableness" criteria it would seem that 30% compliant would mean only one test action would be needed to be completed by the indicated deadline and the next one would be required no later than 6 years from that first test. It is recommended that the implementation plan document be improved to clarify this issue. The consideration of comments response to the above did not completely address the issue that led to the comment. In the Tables in PRC-005-2 there are maintenance items that an entity may not have had in their PRC-005-1 compliance program even though they did have a compliant maintenance program (e.g. battery continuity testing) for that Protection System component. As the transition is made to the PRC-005-2 requirement the above clarification should be made to better define what achievement of PRC-005-2 compliance is for that component.
		2. Section 4.2.2 includes UFLS systems installed per the ERO requirements - excluding any additional UFLS systems that a utility has on their system. Section 4.2.3 includes UVLS systems "installed to prevent system voltage collapse or voltage instability for BES reliability". It is assumed that this would only include UVLS systems required by the ERO, but it is not clear as to what is in scope. It is suggested that the wording of 4.2.3 be changed to match the wording in 4.2.2.
		3. In the implementation plan in the R2 and R3 requirements plans, in item a. of each there is a parenthetical statement regarding generating plant scheduled outage intervals. A similar parenthetical statement should be added to the b. and c. items of each of these plans.

		4. The purpose statement of the standard seems to be inconsistent with the applicability section. To correct this it is suggested that the words “affecting the reliability” be removed from the purpose statement.
		5. For consistency with the changes from 3 months to 4 months in the tables of the standard it is suggested that the second item in Table 1-4(b) be changed from 6 calendar months to 7 calendar months.
		6. In the tables for dc Supply the term “unit-to-unit” is used along with “intercell” when referring to measurement of connection resistance. From the applicable IEEE standards (e.g. IEEE 450) the standard terminology seems to be “intercell”. It is recommended that the “unit-to-unit” term be removed to avoid confusion regarding what is to be verified.

Response: Thank you for your comments. 1. **The SDT agrees with your comment and has modified the Implementation plan to better indicate that, for activities being added to an entity's program as part of PRC-005-2 implementation, evidence will be available to show only a single performance of the activity until a full maintenance interval has transpired following initial implementation.** 2. **Entities are required to install UFLS per PRC-007; there are no standards which require entities to install UVLS. However, if entities choose to install UVLS to meet minimum system performance requirements, several standards (including the current PRC-011 and the proposed PRC-005-2) apply. Section 4.2.3 is specifically intended to address these UVLS.** 3. **The SDT provided the allowance for generator plants to allow them until their first maintenance outage to begin program implementation. It is believed that the entity would then likely perform all maintenance on the protection system for a given generator, GSU and, if so equipped, generator connected station auxiliary transformer during that maintenance window. It seems unlikely that an entity would perform maintenance on only a portion of a protection system. Thus, the SDT concludes that inclusion of the parenthetical to the 2nd and 3rd bullets would only add confusion and provide little or no benefit to generator plants in the implementation of their program.** 4. **The purpose of the standard expresses the general intent of the standard, and is further clarified by the Applicability.** 5. **The SDT believes that a 6-month interval is appropriate for these activities.** 6. **The term "unit-to-unit" is used for the conductor utilized to connect one multi-celled battery jar to an adjacent multi-celled battery jar. The SDT does not believe this terminology causes wide spread confusion.**		
Manitoba Hydro		-Definition of Protection System Maintenance Program: The definition included in the proposed PRC-005-2 is not the same as the definition provided in the document "Definition for Approval", which also includes items "Upkeep" and "Restore".
Response: Thank you for your comments. **The SDT agrees with your observation and will review the associated documents to attain consistency.**		

American Transmission Company		a) Change the text of "Standard PRC-005-2 - Protection System Maintenance" Table 1-5 on page 19, Row 1, Column 3 to: "Verify that each a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Or alternatively, "Electrically operate each interrupting device every 6 years." Trip coils are designed to be energized no longer than the breaker opening time (3-5 cycles). They are robust devices that will successfully operate the breaker for 5,000-10,000 electrical operations. The most likely source of trip coil failure is the breaker operating mechanism binding, thereby preventing the breaker auxiliary stack from opening and keeping the trip coil energized for too long of a time period. Therefore, trip coil failure is a function of the breaker mechanism failure. Exercising the breakers and circuit switchers is an excellent practice. We would encourage language that would suggest this task be done every 2 years, not to exceed 3 years. Exercising the interrupting devices would help eliminate mechanism binding, reducing the chance that the trip coils are energized too long. The language as currently written in Table 1-5 row 1, will also have the unintentional effect of changing an entities existing interrupting device maintenance interval (essentially driving interrupting device testing to a less than 6 year cycle). b) Change the text of "Standard PRC-005-2 - Protection System Maintenance" Table 1-5 on page 19, Row 3, Column 2 to: "12 calendar years" The maximum maintenance interval for "Electromechanical lockout and/or tripping devices which are directly in a trip path from the protective relay to the interrupting device trip coil" should be consistent with the "Unmonitored control circuit" interval which is 12 calendar years.In order to test the lockout relays, it may be necessary to take a bus outage (due to lack of redundancy and associated stability issues with delayed clearing). Increasing the frequency of bus outages (with associated lines or transformers) will also increase the amount of time that the BES is in a less intact system configuration. Increasing the time the BES is in a less intact system configuration also increases the probability of a low frequency, high impact event occurring. Therefore, the Maximum Maintenance Interval should be 12 years for lockout relays. c) ATC's remaining concern for PRC-005-2 is with definition and timelines established in Table 1-5. ATC is recommending a negative ballot since, as written, the testing of "each" trip coil and the proposed maintenance interval for lockout testing will result in the increased amount of time that the BES is in a less intact system configuration. ATC hopes that the SDT will consider these changes.

Response: Thank you for your comments. a) **While the SDT agrees with much of your observation about circuit breaker operations, this standard applies to Protection System maintenance and per the Protection System definition does not include the entire circuit breaker. As such we are limited to exercising the trip coils and seeing that they have the intended effect on the interrupting device. A simple cycling of the breaker should have minimal impact on the scheduling of the entities breaker maintenance program.** b) **The SDT believes that electromechanical lockout relays need periodic operation. As such, these devices are required to be exercised at the same 6 year interval required for electromechanical relays. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed. Performance-based maintenance is an option if you want to extend your intervals beyond 6 years. The SDT, however, has modified Table 1-5 to remove other auxiliary relays, etc, from this activity, and clarified that the verification of such devices is included within the 12-year unmonitored control circuitry verification.** c) **As noted above, the SDT has modified Table 1-5 to remove other auxiliary relays, etc, from the 6-year activity, and clarified that the verification of such devices is included within the 12-year unmonitored control circuitry verification. However, the SDT believes that the other activities addressed in your comment need to be performed as reflected in Table 1-5.**		
Southern Company Transmission		Table 1-5: Need clarification on "continuity and energization or ability to operate". What does this mean?
Response: Thank you for comment. **This entry in Table 1-5 has been modified to "Control circuitry whose integrity is monitored and alarmed". Section 15.3 of the Supplementary Reference and FAQ document provides additional discussion on this topic.**		
Utility Services, Inc		Thank you for the opportunity to address the new documentation and for your efforts.
Response: Thank you for comment.		

ITC Holdings		ITC Holdings continues to object to the requirement to exercise auxiliary relays on a 6 year interval. We repeat our previous comments as follows: "It has been our experience that trip failures are rare and that our present 10 year control, trip tests, and other related testing are sufficient in verifying the integrity of the scheme. Section 8.3 of the Supplementary Reference notes statistical surveys were done to determine the maintenance intervals. Were auxiliary relays included in these surveys in such a way to verify that they indeed require a 6 year maintenance interval? We recommend they be considered part of the control circuitry, with a 12 year test cycle." Previous responses from the SDT were: "The SDT believes that the appropriate interval for electromechanical devices such as aux or lockout relays should remain at 6 years, as these devices contain "moving parts" which must be periodically exercised to remain reliable." ITC requests that the statistical basis for the 6 year interval be published. If it is not clear that lockout relays and other auxiliary relays must be exercised on a 6 year interval, then the requirement should be changed to 12 years.
Response: Thank you for your comments. **The SDT believes that electromechanical lockout relays need periodic operation. As such, these devices are required to be exercised at the same 6 year interval required for electromechanical relays. The SDT recognizes the risk of human error trips when working with testing of lockout devices but believes these risks can be managed. Performance-based maintenance is an option if you want to extend your intervals beyond 6 years. The SDT has modified Table 1-5 to remove other auxiliary relays, etc, from this activity, and clarified that the verification of such devices is included within the 12-year unmonitored control circuitry verification as you have suggested.**		
Ingleside Cogeneration LP		Ingleside Cogeneration, LP, continues to believe that the six year requirement to verify channel performance on associated communications equipment will prove to be more detrimental than beneficial on older relays. Clearly newer technology relays which provide read-outs of signal level or data-error rates will easily verified, but the tools which measure power levels and error rates on non-monitored communication links are far more intrusive. After the technician uncouples and re-attaches a fiber optic connection, the communications channel may be left in worse shape after verification than it was prior to the start of the test.

Response: Thank you for your comments. **There are less intrusive ways to verify channel performance that do not require disconnecting communication terminations. It is up to the entity to determine specific maintenance techniques.**		
CenterPoint Energy		For the "Unmonitored control circuitry associated with protective functions", the Table 1-5 requirement is to "Verify all paths of the trip circuits through the trip coil(s) of the circuit breakers or other interrupting devices" every 12 calendar years. CenterPoint Energy recommends this requirement be revised to "No periodic maintenance specified". CenterPoint Energy believes that verifying all tripping paths is a commissioning task, not a preventive maintenance task. CenterPoint Energy performs such checks on new stations and whenever expansion or modification of existing stations dictates such testing. This type of testing can negatively impact BES system reliability with the outages that are required and by exposing the electric system to incorrect tripping. Likewise, CenterPoint Energy recommends the requirement in Table 1-5 to "Verify all paths of the control circuits essential for proper operation of the SPS" every 12 years be revised to "No periodic maintenance specified".
Response: Thank you for your comments. **The SDT believes that it is possible to manage the risks that you describe and that performance of these trip path verifications will be an overall benefit to the reliability of the BES.**		
Oncor Electric Delivery Company LLC		PRC-005-2 is a vast improvement over the vagueness of the existing standard (PRC-005-1), that the new standard makes compliance much easier than the present standard. The new standard recognizes the advances in relay technology and reliability, particularly the benefits of microprocessor based relays. The standard also provides greater flexibility on its implementation while recognizing the benefits of a performance based methodology, particularly as it relates to battery testing. The revised standard eliminates the requirement for a "summary of maintenance and testing procedures" which was vague and provided no real value to the registered entities. Operational and administrative efficiencies can be realized by consolidating the relay testing and maintenance requirements into one standard (PRC-005-1, PRC-008-0, PRC-011-0, PRC-017-0).
Response: Thank you for your comments.		

City of Austin dba Austin Energy		If a Registered Entity has a PSMP that is more stringent than the intervals in PRC-005-2, the Registered Entity should not be considered out of compliance if it fails to meet its internal interval but remains within the interval set forth in PRC-005-2.
Response: Thank you for your comments. The standard and the Supplementary Reference and FAQ document have been changed to address your concerns. Specifically, Requirement R1 part 1.3 has been removed; Requirement R3 has been revised so that, for time-based programs, entities shall comply with the tables; Requirement R4 has been added to address performance-based maintenance, and Requirement R5 has been added to address Unresolved Maintenance Issues.		
BGE		When the term “Maintenance Correctable Issue” was revised to “Unresolved Maintenance Issue”, it appears that the PRC-005-2 Protection System Maintenance / Supplementary Reference and FAQ document was not properly updated to reflect this change. There are inconsistencies throughout the entire document were the old term is still showing up instead of the new term, and vice versa.
Response: Thank you for your comments. **The SDT has attempted to correct the terminology inconsistencies you have mentioned between the Standard and the Supplementary Reference and FAQ document.**		
VRFs/VSLs		
Xcel Energy, Inc.	Negative Ballot	The VSL for R3 is confusing because of the lack of a specified time horizon. Are the percentages quoted on an annual schedule basis, an audit period, or a continuous percentage measurement of any previously scheduled maintenance activities? Greater clarity is needed on the intent of this VSL.
Response: Thank you for your comment. **The VSLs that use a graduated VSL have been revised based, in part, on the comments you have provided. The percentages relate to the number of violations reported within the compliance monitoring period relative to the number of components within that component type.**		

Ameren Services	Negative Poll	The VRF for R3 should be Low. Many entities presently do not perform some of the specified maintenance activities on some of their components. The risk to the BES is quite low as proven by the extremely reliable BES performance. We are not aware of such omissions in Protection System performance leading to widespread outages, cascading or uncontrolled separation. This coupled with NERC's insistence on 100% perfect completion of all maintenance for even the Lower VSL leads to an inappropriate and unjustified VRF/VSL combination.
Response: The VRF value of "high" stems from consideration of an entity not performing any maintenance and testing of their Protection System. Specifically, a "high" VRF, for a planning time horizon requirement, addresses violations of requirements that could directly cause or contribute to BES instability, separation, or cascading. While not every failure to properly perform maintenance WILL do these things, they can very well contribute to them, as evidenced by involvement of Protection Systems in every recent significant BES disturbance.		
Flathead Electric Cooperative	Negative Poll	do not believe the severe VSL should apply to distributed UFLS
Response: The VSL is a measure of the completeness of the execution of a requirement. Where a binary evaluation of compliance with a particular requirement is prescribed, the NERC VSL guidelines require the violation level to be severe. If the compliance can be demonstrated to be partially complete, a graduated violation severity level is allowed. The NERC Criteria for setting Violation Severity Levels states that it is preferable to have four VSLs for each requirement.		
Independent Electricity System Operator	Negative Poll	The IESO continues to disagree with the High VRF for R3 which asks for implementing the maintenance plan (and initiate corrective measures) whose development and content requirements (R1 and R2) themselves have a Medium VRF. Failure to develop a maintenance program with the attributes specified in R1, and stipulation of the maintenance intervals or performance criteria as required in R2, will render R3 not executable. Hence, we reiterate our position that the VRF for R3 be changed to Medium.

Response: The VRF value of "high" stems from consideration of an entity not performing any maintenance and testing of their Protection System. Specifically, a "high" VRF, for a planning time horizon requirement, addresses violations of requirements that could directly cause or contribute to BES instability, separation, or cascading. While not every failure to properly perform maintenance WILL do these things, they can very well contribute to them, as evidenced by involvement of Protection Systems in every recent significant BES disturbance.		
Liberty Electric Power LLC	Negative Poll	The percentage structure on unresolved maintenance issues presents problems. Smaller entities are unlikely to ever have more than a handful of unresolved issues, meaning a single failure to initiate would automatically be a High VSL. There would also be a disincentive to close out issues from fear that "resolving" them could potentially increase a violation level on a discovered issue.
Response: The VSLs relating to Unresolved Maintenance Issues have been revised to graduated VSLs using a count of violations, rather than a percentage.		
Xcel Energy, Inc.	Negative Poll	The VSL for R3 is confusing because of the lack of a specified time horizon. Are the percentages quoted on an annual schedule basis, an audit period, or a continuous percentage measurement of any previously scheduled maintenance activities? Greater clarity is needed on the intent of this VSL.
Response: Thank you for your comment. **The VSLs that use a graduated VSL have been revised based, in part, on the comments you have provided. The percentages relate to the number of violations reported within the compliance monitoring period relative to the number of components within that component type.**		

END OF REPORT