Consideration of Comments on the 4th Draft of Protection System Maintenance and Testing — Project 2007-17

The Protection System Maintenance and Testing Drafting Team thanks all commenters who submitted comments on the 4th draft of the Protection System Maintenance standard, its implementation plan, and the associated reference document. The standard and associated documents were posted for a 30-day public comment period from April 13, 2011 through May 13, 2011. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 55 sets of comments, including comments from more than 176 people from approximately 103 companies representing 10 of the 10 Industry Segments as shown in the table on the following pages.

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

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

In addition, a successive ballot of the standard was conducted from May 3-13, 2011, and a non-binding poll of the Violation Risk Factors and Violation Severity Levels was conducted from May 3-16, 2011 and comments from the ballot and poll have been included in this report.

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, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received:

Purpose:

The SDT modified the Purpose to state, "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" in response to previous Quality Review comments.

Applicability:

Several comments were offered, suggesting that PRC-005-2 needs to be consistent with the interpretation in Project 2009-17, now implemented as PRC-005-1a, and the SDT modified Applicability 4.2.1 for better consistency with the interpretation 4.2.1 as shown below:

> 4.2.1. Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.).

Requirement R1:

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Requirement R1 was modified as shown below for improved specificity, based on stakeholder comments:

R1. Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2.

Tables

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

Implementation Plan

Some commenters noted that for entities not subject to regulatory approvals, the implementation plan should be longer so that all entities have sufficient time for implementation. The team did modify the Implementation Plan to provide for a lengthened implementation period for R1 and the less-than-1-calendar-year activities in R2 and R3 to allow entities not subject to regulatory approvals of 9 additional months following BOT approvals, and, for the remaining activities, of 12 additional months following BOT approvals, to be more consistent with the expected Regulatory Approval timelines. Additionally, all "calendar year" implementation periods were revised to "months" for additional clarity.

VLSs:

VSLs for Requirement R1

- Phased VSLs were added to address R1 Part 1.1, which was previously addressed only as a "Severe" VSL.
- A reference was added within the R1 VSL to Part 1.3.
- R1 High VSL was revised to add a reference to Table 2.

VSLs for Requirement R2

- One element of the R2 VSL was made binary (Severe), rather than "phased" (in two steps), in response to several comments.
- Many commenters pointed out an error (which was corrected by the SDT) within the VSL for R2, where the Lower and High VSLs contained identical text.

VSLs for Requirement R3

- The R3 VSLs were revised to replace "complete" with "implement and follow" for consistency with the Requirement.
- Other minor editorial changes were made throughout the VSLs in response to comments.

Supplementary Reference and FAQ

- The commenters were generally supportive of the reference document.

- Several questions regarding the enforceability of this document were posed, and the SDT explained that the document is a supporting reference and not enforceable – only standard requirements are enforceable.
- A variety of suggestions were offered regarding additional information for the document, which largely resulted in modifications to the Supplementary Reference document. One specific suggestion of note (resulting in additional discussion within the document) requested a FAQ regarding "Calendar Year".
- Several commenters posed questions regarding "grace periods" and "PSMPs established by entities that are more stringent than the requirements within the standard". No additional changes were made due to these questions. If an entity develops a PSMP that includes time intervals that are more stringent than those in the standard, the entity will be audited against the intervals in its PSMP.

Definitions:

- Several comments were offered regarding Maintenance Correctable Issues, and resulted in modifying this definition to be "…such that the deficiency cannot be corrected during the performance of the maintenance activity …"

Unresolved Minority Views:

- Many comments were offered objecting to the 3-calendar-month intervals for station dc supply and communications systems, and suggesting that a 3-calendar-month interval requires entities to schedule these activities for 2-calendar-months in order to assure compliance. The SDT did not modify the standard in response to these comments, and responded that the intervals were appropriate, and that entities should be able to assure compliance on a 3-calendar-month schedule by using program oversight. The "Supplementary Reference and FAQ" document was augmented with additional explanatory text.
- 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 comments were offered questioning various aspects of Applicability 4.2.5.4 (generation auxiliary transformers). No changes were made in response to these comments, and responses were offered illustrating why these transformers are included.
- Many comments were offered, questioning the propriety of including distribution system Protection Systems, almost all related to UFLS/UVLS. The SDT explained that these Protection Systems are appropriate to be included for consistency with legacy standards PRC-008, PRC-011, and PRC-017, and noted that their inclusion is consistent with Section 202 of the NERC Rules of Procedure.
- Several comments were offered, objecting to the 6-calendar-year interval for lockout and auxiliary relays. The SDT declined to adopt the requested changes, and noted that these "electromechanical" devices with "moving parts" share failure mechanisms with electromechanical protective relays and that the intervals should be identical.

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 Reliablity Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	New Brunswick Power Transmission	NPCC	1

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

	Additional Member	Additional Organization	Region	Segment Selection
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	1
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Marie Knox	MISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joe O'Brien	NIPSCO	RFC	6
2.	Gary Carlson	Michigan Public Power Agency	RFC	3

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Michael Gildea	Dominion Resources Services, Inc.	SERC	3
2.	Michael Crowley	Dominion Virginia Power	SERC	1
3.	Louis Slade	Dominion Resources Services, Inc.	RFC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Terry L. Blackwell	Santee Cooper	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	S. T. Abrams	Santee Cooper	SERC	1
2.	Glenn Stephens	Santee Cooper	SERC	1
3.	Rene Free	Santee Cooper	SERC	1
4.	Kevin Bevins	Santee Cooper	SERC	1
5.	Bridgett Coffman	Santee Cooper	SERC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender	BPA, Transmission, SPC Technical Svcs	WECC	1
2.	Jason Burt	BPA, Transmission, RAS and Data Systems	WECC	1
3.	Robert France	BPA, Transmission, PSC Technical Svcs	WECC	1
4.	Mason Bibles	BPA, Transmission, Sub Maint and HV Engineering	WECC	1
5.	Deanna Phillips	BPA, Transmission, FERC Compliance	WECC	1

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jonathan Hayes	SPP reliability standard development Team		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Reilly	Oklahoma Gas and Electric	SPP	1, 3, 5
2.	Edwin Averill	Grand Rvier Dam Authority	SPP	1, 3, 5
3.	James Hutchinson	Oklahoma Gas and Electric	SPP	1, 3, 5
4.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
5.	Rick Bartlett	Independence Power & Light	SPP	1, 3, 5
6.	Sean Simpson	Board of Public Utilities, City of McPherson	SPP	1, 3, 5
7.	Mark Wurm	Board of Public Utilities, City of McPherson	SPP	1, 3, 5
8.	Joe Border	Board of Public Utilities, City of McPherson	SPP	1, 3, 5
9.	Michelle Corley	CLECO	SPP	1, 3, 5, 6

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carlton Bradshaw	Atlantic Electric		1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Thompson	River Operations Engineering	SERC	NA
2.	Frank Cuzzort	Nuclear Power Engineering	SERC	NA

3.	Robert Brown	Nuclear Power Engineering	SERC	NA
4.	Robert Mares	Fossil Power Engineering	SERC	NA
5.	Paul Barlett	Transmission O&M Support	SERC	NA
6.	Pat Caldwell	Transmission O&M Support	SERC	NA
7.	Rusty Hardison	Transmission O&M Support	SERC	NA
8.	Jerry Findley	Communications/SCADA	SERC	NA

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Group	Jose Landeros	Imperial Irrigation District	X		X	X		X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Epifanio Martinez		WECC	
2.	Fernando Gutierrez		WECC	
3.	Gerardo Landeros		WECC	
4.	Tony Allegranza		WECC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Ron Sporseen	PNGC Comment Group	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.	Roman Gillen	Consumer's Power Inc.	WECC	3
4.	Roger Meader	Coos-Curry Electric Cooperative	WECC	3
5.	Dave Hagen	Clearwater Electric Cooperative	WECC	3
6.	Dave Sabala	Douglas Electric Cooperative	WECC	3
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 Electric Cooperative	WECC	3
11.	Jon Shelby	Northern Lights Electric Cooperative	WECC	3
12.	Ray Ellis	Okanogan Electric Cooperative	WECC	3
13.	Aleka Scott	PNGC Power	WECC	4

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

14.	Heber Carpenter	Raft River Electric Cooperative	WECC	3
15.	Ken Dizes	Salmon River Electric Cooperative	WECC	3
16.	Steve Eldrige	Umatilla Electric Cooperative	WECC	3
17.	Marc Farmer	West Oregon Electric Cooperative	WECC	3
18.	Margaret Ryan	PNGC Power	WECC	8
19.	Stuart Sloan	Consumer's Power Inc.	WECC	1
20.	Rick Paschal	PNGC Power	WECC	3

11.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
10.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
11.	Scott Nickels	Rochester Public Utilties	MRO	4
12.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
13.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

12.	Group	Daniel Herring	The Detroit Edison Company			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	David A Szulczewski	Engineering	RFC	3, 4, 5
2.	Steven P Kerkmaz	Engineering	RFC	3, 4, 5

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.	Nicole M Syc	Engineering	RFC	3, 4, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Albert DiCaprio	ISO/RTO Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Terry Bilke	MISO	RFC	2
2.	Patrick Brown	PJM	RFC	2
3.	Greg Campoli	ISO-NY	NPCC	2
4.	Mike Falvo	IESO	NPCC	2
5.	Matt Goldberg	ISO-NE	NPCC	2
6.	Kathleen Goodman	ISO-NE	NPCC	2
7.	Ben Li	IESO	NPCC	2
8.	Steve Myers	ERCOT	ERCOT	2
9.	Bill Phillips	MISO	RFC	2
10.	Mark Thompson	AESO	WECC	2
11.	Don Weaver	NBSO	NPCC	2
12.	Mark Westendorf	MISO	RFC	2
13.	Charles Yeung	SPP	SPP	2

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
2.	Jim Kinney	FE	RFC	1
3.	Brian Orians	FE	RFC	5
4.	Ken Dresner	FE	RFC	5
5.	Bill Duge	FE	RFC	5
6.	Craig Boyle	FE	RFC	1
7.	Mark Pavlick	FE	RFC	1, 3, 4, 5, 6
8.	Lenny Lee	FE	RFC	1
9.	J. Chmura	FE	RFC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
10.	Rusty Loy	FE	RFC 5										
11.	Hugh Conley	FE	RFC 1										
12.	Frank Hartley	FE	RFC 1										
15.	Individual	Cynthia S. Bogorad	Transmission Access Policy Study Group	X		X	X	X	X				
16.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
17.	Individual	David Youngblood	Luminant						X				
18.	Individual	Silvia Parada Mitchell	NextEra Energy	X		X		X	X				
19.	Individual	David Youngblood	Luminant					X					
20.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
21.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
22.	Individual	Janet Smith, Regulatory Affairs Supervisor	Arizona Public Service Company	X		X		X	X				
23.	Individual	Robert W. Kenyon	NERC - EA & I										
24.	Individual	Daniel Duff	Liberty Electric Power LLC					X					
25.	Individual	Russ Schneider	FHEC			X							
26.	Individual	Michelle D'Antuono	Ingleside Cogeneration LP					X					
27.	Individual	Beth Young	Tampa Electric Company	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
28.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
29.	Individual	Linda Jacobson	Farmington Electric Utility System			X							
30.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
31.	Individual	Steve Alexanderson	Central Lincoln			X	X					X	
32.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
33.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
34.	Individual	Mike Hancock	Shermco Industries										
35.	Individual	Michael Crowley	Dominion Virginia Power	X									
36.	Individual	Edward J Davis	Entergy Services	X		X		X	X				
37.	Individual	Thad Ness	American Electric Power	X		X		X	X				
38.	Individual	Jose H Escamilla	CPS Energy	X									
39.	Individual	Melissa Kurtz	US Army Corps of Engineers	X				X					
40.	Individual	Kenneth A. Goldsmith	Alliant Energy				X						
41.	Individual	Kirit Shah	Ameren	X		X		X	X				
42.	Individual	Rex Roehl	Indeck Energy Services					X					
43.	Individual	Kevin Luke	Georgia Transmission Corporation	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
44.	Individual	Andrew Z Pusztai	American Transmission Company, LLC	X									
45.	Individual	John Bee	Exelon	X		X		X					
46.	Individual	Glen Sutton	AtCO Electric ltd	X									
47.	Individual	Claudiu Cadar	GDS Associates	X									
48.	Individual	Gerry Schmitt	BGE	X									
49.	Individual	Michael Moltane	ITC	X									
50.	Individual	Bill Middaugh	Tri-State G&T	X									
51.	Individual	Don Schmit	Nebraska Public Power District	X		X		X					
52.	Individual	Michael Falvo	Independent Electricity System Operator		X								
53.	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X		X			
54.	Individual	Gary Kruempel	MidAmerican Energy Company	X		X		X					
55.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				

The following balloters submitted comments either with a comment form or with their ballot:

1	Edward P. Cox	AEP Marketing	6
2	Brock Ondayko	AEP Service Corp.	5
3	Kenneth Goldsmith	Alliant Energy Corp. Services, Inc.	4
4	Kirit S. Shah	Ameren Services	1
5	Paul B. Johnson	American Electric Power	1
6	Jason Shaver	American Transmission Company, LLC	1
7	Robert D Smith	Arizona Public Service Co.	1
8	John Bussman	Associated Electric Cooperative, Inc.	1
9	Joseph S. Stonecipher	Beaches Energy Services	1
10	Donald S. Watkins	Bonneville Power Administration	1
11	Francis J. Halpin	Bonneville Power Administration	5
12	William Mitchell Chamberlain	California Energy Commission	9
13	Steve Alexanderson	Central Lincoln PUD	3
14	Matt Culverhouse	City of Bartow, Florida	3
15	Linda R. Jacobson	City of Farmington	3
16	Gregg R Griffin	City of Green Cove Springs	3
17	Paul Morland	Colorado Springs Utilities	1
18	Christopher L de Graffenried	Consolidated Edison Co. of New York	1
19	Peter T Yost	Consolidated Edison Co. of New York	3
20	Wilket (Jack) Ng	Consolidated Edison Co. of New York	5
21	Nickesha P Carrol	Consolidated Edison Co. of New York	6
22	Brenda Powell	Constellation Energy Commodities Group	6
23	Amir Y Hammad	Constellation Power Source Generation, Inc.	5
24	David A. Lapinski	Consumers Energy	3
25	David Frank Ronk	Consumers Energy	4
26	James B Lewis	Consumers Energy	5

27	Kenneth Parker	Entegra Power Group, LLC	5
28	Joel T Plessinger	Entergy	3
29	Terri F Benoit	Entergy Services, Inc.	6
30	Robert Martinko	FirstEnergy Energy Delivery	1
31	Kevin Querry	FirstEnergy Solutions	3
32	Kenneth Dresner	FirstEnergy Solutions	5
33	Mark S Travaglianti	FirstEnergy Solutions	6
34	Dennis Minton	Florida Keys Electric Cooperative Assoc.	1
35	Frank Gaffney	Florida Municipal Power Agency	4
36	David Schumann	Florida Municipal Power Agency	5
37	Richard L. Montgomery	Florida Municipal Power Agency	6
38	Thomas E Washburn	Florida Municipal Power Pool	6
39	Luther E. Fair	Gainesville Regional Utilities	1
40	Claudiu Cadar	GDS Associates, Inc.	1
41	Guy Andrews	Georgia System Operations Corporation	4
42	Gordon Pietsch	Great River Energy	1
43	Gwen Frazier	Gulf Power	3
44	Ronald D. Schellberg	Idaho Power Company	1
45	Bob C. Thomas	Illinois Municipal Electric Agency	4
46	Rex A Roehl	Indeck Energy Services, Inc.	5
47	Michael Moltane	International Transmission Company Holdings Corp	1
48	Garry Baker	JEA	3
49	Stan T. Rzad	Keys Energy Services	1
50	Larry E Watt	Lakeland Electric	1
51	Mace Hunter	Lakeland Electric	3
52	Paul Shipps	Lakeland Electric	6
53	Daniel Duff	Liberty Electric Power LLC	5
54	Brad Jones	Luminant Energy	6
55	Mike Laney	Luminant Generation Company LLC	5
56	Joseph G. DePoorter	Madison Gas and Electric Co.	4

57	Joe D Petaski	Manitoba Hydro	1
58	Greg C. Parent	Manitoba Hydro	3
59	Mark Aikens	Manitoba Hydro	5
60	Daniel Prowse	Manitoba Hydro	6
61	Jason L. Marshall	Midwest ISO, Inc.	2
62	John S Bos	Muscatine Power & Water	3
63	Saurabh Saksena	National Grid	1
64	Arnold J. Schuff	New York Power Authority	1
65	Gerald Mannarino	New York Power Authority	5
66	Guy V. Zito	Northeast Power Coordinating Council, Inc.	10
67	William SeDoris	Northern Indiana Public Service Co.	3
68	Joseph O'Brien	Northern Indiana Public Service Co.	6
69	John Canavan	NorthWestern Energy	1
70	Douglas Hohlbaugh	Ohio Edison Company	4
71	Mark Ringhausen	Old Dominion Electric Coop.	4
72	Margaret Ryan	Pacific Northwest Generating Cooperative	8
73	Sandra L. Shaffer	PacifiCorp	5
74	Tom Bowe	PJM Interconnection, L.L.C.	2
75	John C. Collins	Platte River Power Authority	1
76	Terry L Baker	Platte River Power Authority	3
77	Carol Ballantine	Platte River Power Authority	6
78	David Thorne	Potomac Electric Power Co.	1
79	Jerzy A Slusarz	PSEG Power LLC	5
80	Henry E. LuBean	Public Utility District No. 1 of Douglas County	4
81	Steven Grega	Public Utility District No. 1 of Lewis County	5
82	Greg Lange	Public Utility District No. 2 of Grant County	3
83	Terry L. Blackwell	Santee Cooper	1
84	Lewis P Pierce	Santee Cooper	5
85	Suzanne Ritter	Santee Cooper	6
86	Pawel Krupa	Seattle City Light	1

87	Dana Wheelock	Seattle City Light	3
88	Hao Li	Seattle City Light	4
89	Michael J. Haynes	Seattle City Light	5
90	Dennis Sismaet	Seattle City Light	6
91	Horace Williamson	Southern Company	1
92	William D Shultz	Southern Company Generation	5
93	Scott M. Helyer	Tenaska, Inc.	5
94	Larry Akens	Tennessee Valley Authority	1
95	George T. Ballew	Tennessee Valley Authority	5
96	Marjorie S. Parsons	Tennessee Valley Authority	6
97	Keith V Carman	Tri-State G & T Association, Inc.	1
98	Janelle Marriott	Tri-State G & T Association, Inc.	3
99	Barry Ingold	Tri-State G & T Association, Inc.	5
100	John Tolo	Tucson Electric Power Co.	1
101	Melissa Kurtz	U.S. Army Corps of Engineers	5
102	Martin Bauer P.E.	U.S. Bureau of Reclamation	5
103	Ric Campbell	Utah Public Service Commission	9
104	Louise McCarren	Western Electricity Coordinating Council	10
105	Linda Horn	Wisconsin Electric Power Co.	5
106	James R. Keller	Wisconsin Electric Power Marketing	3
107	Anthony Jankowski	Wisconsin Energy Corp.	4
108	James A Ziebarth	Y-W Electric Association, Inc.	4
109	Kristina M. Loudermilk		8

1. The SDT has restructured the Table for Station DC Supply, separating it into six sub-tables individually addressing the various different technologies. Do you agree that the restructured tables provide more clarity? If not, please provide specific suggestions for improvement.

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

A number of commenters continued to object to the “3 Calendar Month” maintenance intervals, and the SDT chose not to modify the standard. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems and suggestions to extend the maintenance intervals to 6 or 18 months were not adopted.

Some comments suggested extending the interval to 4 months. Additional discussion (including an example) regarding this item was added to Section 7.1 of the “Supplementary Reference and FAQ”. As explained in the reference, a calendar month begins on the first day of a new month following the month in which the activity was performed. Thus every “3 Calendar Months” means to add 3 months from the last time the activity was performed.

Specific changes made to the tables in response to comments:

Tables 1-1 and 1-3 – References to Table 2 were corrected.

Table 1-4(a) and Table 1-4(d) – Modified header to clarify, “Protection System Station dc supply”

Table 1-4(b) and Table 1-4(c) - Modified header and component attributes to clarify, “Protection System Station dc supply”

Table 1-4(e) - Modified header and component attributes to clarify, “Protection System Station dc supply” and replaced, “distribution breakers” with “non-BES interrupting devices”.

Table 1-4(f) - Modified header to clarify, “Protection System Station dc supply”, modified the seventh table entry for clarity, and added eighth table entry.

Table 1-5 – Added “Associated with Protective Functions” to header

Organization	Yes or No	Question 1 Comment
Tri-State G & T Association, Inc.	Ballot	On Table 1-2, page 11: The standard describes the following component attributes, “Any unmonitored

Organization	Yes or No	Question 1 Comment
(3) (5)	Comment – Affirmative	communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.” How does this apply to redundant communication systems? If the primary communications channel fails the protective relay automatically fails over to the back-up channel and continues to function properly. Are redundant communication channels excluded from this component attribute and associated interval? Also, if a relay is set to operate in a manner typical when communication is not used for protection (i.e. defaulting to step-distance functions with a loss of communication), is the defaulted operation of the relay considered “correct operation” thereby excluding the communication as necessary for its correct operation? Please clarify the term correct operation and how it applies to redundant communication systems and/or the performance of the relay in the absence of communication.
Response: Thank you for your comments. If communication-assisted protection is provided as described in the Applicability of PRC-005-2, it must be tested in accordance with the intervals and activities described in the standard. Redundant equipment and/or channels do not relieve the entity of the responsibility to maintain all equipment as required. An entity is entitled to use any monitoring present on the communications system to adjust its maintenance as established within Table 1-2, and, if sufficient component populations are present and the entity wishes to address the additional included requirements, performance-based maintenance is also available. Correct operation of the protective function means that if the communications system is part of the protection system and loss of it causes the system to fail to meet the schemes protection requirements it has failed. In the example you provide, loss of communications would result in time delay clearing depending on location of the fault. If time delay clearing will be sufficient for your system clearing time requirements, then high speed clearing is not required and the Comm. System would not need to be installed. If it is installed, you must meet the PRC-005 requirements. Redundant communications schemes are installed where high speed clearing is required to meet planning criteria. The second scheme is in place to prevent the line from being removed from service if the primary scheme must be maintained or fails. If redundant schemes are in place, both must meet the PRC-005 standard.		
Tri-State G&T		On Table 1-2, page 11: The standard describes the following component attributes, “Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.” How does this apply to redundant communication systems? If the primary communications channel fails the protective relay automatically fails over to the back-up channel and continues to function properly. Are redundant communication channels excluded from this component attribute and associated interval? Please clarify the term correct operation and how it applies to redundant communication systems.
Response: Thank you for your comments. If communication-assisted protection is provided as described in the Applicability of PRC-005-2, it must be tested in accordance with the intervals and activities described in the standard. Redundant equipment and/or channels do not relieve the entity of the responsibility to maintain all equipment as required. An entity is entitled to use any monitoring present on the communications system to adjust its maintenance as established		

Organization	Yes or No	Question 1 Comment
within Table 1-2, and, if sufficient component populations are present and the entity wishes to address the additional included requirements, performance-based maintenance is also available. Correct operation of the protective function means that if the communications system is part of the protection system and loss of it causes the system to fail to meet the schemes protection requirements it has failed. In the example you provide, loss of communications would result in time delay clearing depending on location of the fault. If time delay clearing will be sufficient for your system clearing time requirements, then high speed clearing is not required and the Comm. System would not need to be installed. If it is installed, you must meet the PRC-005 requirements. Redundant communications schemes are installed where high speed clearing is required to meet planning criteria. The second scheme is in place to prevent the line from being removed from service if the primary scheme must be maintained or fails. If redundant schemes are in place, both must meet the PRC-005 standard.		
Consumers Energy (4)	Ballot Comment - Negative	Relating to Table 1-3, The SDT has advised that the voltage and current inputs must be checked at each individual relay. This may not be difficult if the relays are microprocessor relays (where internal metering may be used), but for the predominant population of electromechanical relays (particularly for current signals), this requirement will necessitate repeated operation of test switches and associated insertion of meters. Such activities will not only be very difficult and time consuming, but will actually be dangerous because of the dangers of accidentally opening current circuits during testing. It should be sufficient to verify the integrity of the series string of protective relays, etc during maintenance activities, as all devices within the series string will be receiving the same values.
Response: Thank you for your comments. Entities can choose how to best manage their risk. If online testing is deemed too risky, offline tests such as, but not limited to, secondary injection, CT excitation test and PT turns ratio tests can be compared to baseline data and be used in conjunction with CT and PT secondary wiring insulation verification tests to adequately “verify the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays”.		
Tri-State G & T Association, Inc. (3) (5)	Ballot Comment - Affirmative	The draft standard requires the PSMP to include maintenance and testing intervals for Station DC supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply). Does this requirement include DC systems (batteries not included in station batteries) used by communication systems necessary for the correct operation of protective functions?
Response: Thank you for your comments. No, an independent DC Supply related only to communication equipment is not considered to be “station dc supply”. The periodic functional observation and testing of the communications equipment is included, but there are no requirements for the independent dc supply.		
Wisconsin Electric Power Co. (5) Wisconsin Electric Power	Ballot Comment - Negative	(1) The maximum maintenance intervals listed in various PRC-005-2 tables are described as “calendar years” which is an undefined term. Since maintenance intervals are critical to this standard, this term should be either clearly defined or explained in the standard. For example, if a component was last tested on 6/1/2005; does that component need to be tested by 6/1/2011 or 12/31/2011 to satisfy its 6 calendar year

Organization	Yes or No	Question 1 Comment
Marketing (3) Wisconsin Energy Corp. (4)		maximum maintenance interval? 2) Clarification and/or direction is desired on the testing of protection systems that contain components owned by various entities. For example, in the instance of non-vertical integrated utilities where a distribution provider has a Protection System that directly trips a transmission owner's circuit breaker(s), how would the distribution provider verify that the trip coil is able to operate the circuit breaker? (3) Maximum testing intervals are defined. Does this imply that there are no minimum testing intervals? In other words, is the maintenance cycle reset anytime maintenance is performed? (4) Requirement R1.1.2 states that" "All batteries associated with the station dc supply component type of a Protection System shall be included in a time-based program as described in Table 1-4." Yet, in Table 1-4 under Component Attributes it refers to "…not having monitoring attributes of Table 1-4(f)." Suggest this statement be made more clear by adding "All batteries associated with the station dc supply component type of a Protection System shall be included in a time-based program as described in Table 1-4., unless the dc supply has the monitoring attributes listed in Table 1-4(f)." (5) Suggest the inspection Maximum Maintenance Interval for inspection of batteries be 4 months instead of 3 months to allow for workforce constraints that may preclude an inspection being performed within a 3 month window. Every 3 months has been found to be more than adequate to observe changing conditions that affect batteries, therefore we feel 4 months would still be sufficient. (6) In Tables 1-4 (a), (b), (c) – What is your interpretation of battery continuity? In other words, what measurements or indications would be acceptable to affirm an acceptable condition? Table 1-4(b) VRLA batteries, Maximum Maintenance Interval 18 Calendar Months, Maintenance Activities, Verify: Battery terminal connection resistance, Verify: Battery intercell or unit-to-unit connection resistance - comment: Add the following qualifier to these resistance checks: "If battery posts are not readily accessible or too small to allow a good connection, follow the manufacturer's recommendation(s)."

Response: Thank you for your comments.

1. A "calendar year" refers to the years on the Julian calendar commonly used, and should be regarded as referring to a numbered year, comprising the months of January through December. For example, 2010 is one calendar year; 2011 is another. A component, with a 6-year interval, which was last tested in 2005, would next have to be tested by the end of 2011.

2. The standard does not prescribe "how" an entity must meet the requirements, only that the requirements must be met. However, all entities listed in the Applicability are "owner entities", and the SDT believes that the owner of the component should be responsible for its maintenance. However, it may be necessary to have records relating to specific activities from the associated entity in order to demonstrate compliance to an auditor.

3. No minimum intervals are provided. To the degree that any maintenance includes all required activities, that maintenance can be recorded as addressing the

Organization	Yes or No	Question 1 Comment
standard and re-setting the interval. 4. A "time-based" program includes extended intervals for those activities that can be effectively performed by condition monitoring. However, this requirement excludes an entity from utilizing performance-based maintenance per R3 and Attachment A. 5. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a "grace period" if adequate program oversight is exercised, and disagrees that the intervals should be extended. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. See Section 7.1 of the "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" for a discussion about "calendar month" 6. In Section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" the SDT gives its interpretation of battery continuity and lists several examples of measurements or indications that would be acceptable to affirm an acceptable condition and contains a discussion of connection resistance. Your comment concerning the inaccessibility of posts or being too small would fit more appropriately as a qualifier there than in the in the standard itself.		
Tennessee Valley Authority (1) (5) (6)	Ballot Comment - Negative	In Table 1-4(a), the requirement to perform battery cell internal ohmic measurements every 18 months for vented lead-acid batteries is excessive, and no technical justification is provided for an 18-month interval. A 3-year internal ohmic test frequency is adequate to prove battery integrity. IEEE 450 does not provide a recommended interval for internal ohmic measurements. For standard capacity testing, the recommended interval is no greater than 25% of expected battery life. Our normal battery life is 20+ years, so the recommended capacity test interval would be about 5 years. EPRI also recommends capacity testing at 5 year intervals. There is no justification for performing internal ohmic measurements every 18 months (which equals every 7.5% interval of the expected battery life). We feel the standard should set the interval for battery internal cell ohmic testing at 3 years.
Response: Thank you for your comments. The Maintenance Activity of evaluating the measured cell/unit internal ohmic values to station battery baseline is an optional activity to verify that the station battery can perform as designed. An owner who desires not to take internal ohmic measurements on a Vented Lead-Acid (VLA) battery can elect to verify that the station battery can perform as designed by conducting a performance, service, or modified performance capacity test of the entire battery bank without ever having to perform any internal ohmic measurement on the battery. The maximum maintenance interval for performing this capacity test on a VLA battery bank is 6 Calendar Years. In section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" - that was posted for review with PRC-005-2 - the SDT answered several Frequently Asked Questions which explain why the 18 month Maximum Maintenance Interval is justified rather than the 3 year frequency that is assumed by some to be adequate.		
Great River Energy (1)	Ballot Comment - Affirmative	1. Table 1-4(b) VRLA Batteries---both" 6 Calendar Months" in the table should be changed to 12 months. This would avoid being in violation if we miss a bank during a "6 month maintenance cycle" 2. Table 1-4(c) Nickel-Cadmium Batteries under the Maintenance Activities column for the 6 Calendar Years--- This maintenance activity should be optional if 18 Calendar Month Activities are completed. Or increase load test to 10 years.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. 1. In the IEEE recommended Practice for Maintenance, Testing and Replacement of VRLA batteries (IEEE SDT 1188) a quarterly inspection should include “Cell/unit internal ohmic values.” Based on this recommendation the SDT believes that extending the Maximum Maintenance Interval of 6 Calendar Months in Table 1-4(b) to 12 months as suggested would be too excessive. The 6 Calendar Months for this maintenance activity will allow an entity to avoid being in violation if they miss a bank by a few days during the quarterly maintenance cycle. 2. In section 15.4 of “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” the SDT answered a Frequently Asked Question explaining why the 6 Calendar Year maintenance activity cannot be optional if the 18 Calendar Month Activity of Table 1-4(c) is performed. The SDT also in the Supplemental Reference & FAQ document justifies why the 6 Calendar Year Maximum Maintenance interval for performing the Maintenance Activity in Table 1-4(c) can not be extended to 10 years as suggested.		
AtCO Electric ltd		Table 1-4: ATCO Electric has a number of remote substations that are difficult to access. 1. The requirement for a 3 calendar month inspection for electrolyte level is too frequent. The requirement would become achievable if electrolyte level inspections were moved to the 18 calendar months category, or if the 3 calendar months frequency were increased to 8 calendar months. 2. Table 1-4(b): for the same reasons, the requirement of a 6 calendar month inspection of individual battery cell/unit internal ohmic values is too frequent. The requirement would become achievable if battery cell/unit internal ohmic value inspections were moved to the 18 calendar months category, or if the 6 calendar months frequency were increased to 14 calendar months. 3. Table 1-4(c): the requirement of a 6 calendar year performance service or modified performance capacity test should be removed. From our experience, there is no benefit in doing battery load tests. Instead, we apply verification of battery intercell resistance as a more efficient method of monitoring battery condition, which provides an 8 to 14 month lead time to replace a battery unit/cell before it goes dead.
Response: Thank you for your comments. 1. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval. If adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month”. 2. In the IEEE recommended Practice for Maintenance, Testing and Replacement of VRLA batteries (IEEE SDT 1188) a quarterly inspection should include “Cell/unit internal ohmic values.” Based on this recommendation the SDT believes that extending the Maximum Maintenance Interval of 6 Calendar Months in Table 1-4(b) to the 18 calendar months category as suggested would be excessive and the SDT notes that this verification may be possible via monitoring methods.”(See Table 1-4(f), component attribute row “Any lead acid battery based …”). The 6 Calendar Months for this maintenance activity will allow an entity to avoid being in violation if they miss a bank by a few days during the quarterly maintenance cycle.		

Organization	Yes or No	Question 1 Comment
3. In section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" the SDT answered a Frequently Asked Question explaining why the 6 Calendar Year maintenance activity cannot be optional if the 18 Calendar Month Activity of Table 1-4(c) is performed. The SDT also in the Supplemental Reference & FAQ document justifies why the 6 Calendar Year Maximum Maintenance interval for performing the Maintenance Activity in Table 1-4(c) can not be removed as suggested.		
Kristina M. Loudermilk (8)	Ballot Comment - Affirmative	1) In Table 1-4(b) under the Component Attributes, the sentence begins with Station dc supply; while the other 1-4 tables begin with Protection System Station dc. I propose to make it consistent with the other tables. 2) Table 1-4(e) mentions Maximum intervals and references another table. Is there an easier way in the Standard to send the same information without having them flip pages? As another example in every Component Attribute in Table 1-4(f) we mention (See Table 2). Could it be possible to make that a note, instead of placing it under each attribute? It seems overwhelming when looking at these and for each one that is read, flip over to Table 2. I feel like some of these references give the feel of a scavenger hunt. I am not sure if anything can be done, but thought I would mention it.
Response: Thank you for your comments. 1.The Tables have been modified to use "Protection System Station dc supply" 2. In this regard, the SDT has tried several methods of presentation for this information. Of all methods reviewed, including the one you suggest, the SDT has determined that the method currently represented in the Tables represents the best compromise.		
Consumers Energy (4)	Ballot Comment - Negative	Relative to the 18-month activity to measure battery terminal connection resistance in Table 1-4, measuring the battery terminal connection resistance for all terminals of the battery is an involved process that may force the battery (and thus the system) out-of-service, or alternatively the use of a temporary battery, for the duration of the activity. We suggest that a 6-year interval for this involved and invasive activity is appropriate and adequate. We also suggest that it should alternatively be sufficient to instead re-torque all battery terminal connections at the same interval.
Response: Thank you for your comments. In IEEE Standards 450, 1188, and 1106 for vented lead-acid (VLA), valve-regulated lead-acid (VRLA) and nickel-cadmium (NiCd) batteries respectively state that a "yearly inspection" should include "Cell-to-cell and terminal connection resistance", "Cell-to-cell and detail resistance of entire battery", and "Condition and resistance of cable connections." Based on these IEEE recommendations the SDT believes that the Maximum Maintenance Interval of 18 Calendar Months for this Maintenance activity will allow an entity to avoid being in violation if they miss a bank by a few weeks during the yearly maintenance cycle. In section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" - that was posted for review with PRC-005-2 - the SDT explains what hazards can result from high connection resistance. Also in the Supplementary Reference the SDT references where in the IEEE Standards entities can find excellent information and examples of performing this non-intrusive Maintenance Activity. The SDT respectively disagrees with the premise that the activity to		

Organization	Yes or No	Question 1 Comment
measure battery terminal connection resistance in Table 1-4 is “an involved process that may force the battery (and thus the system) out-of-service, or alternatively the use of a temporary battery, for the duration of the activity.” Members of the SDT are familiar with numerous Transmission Owners, Generator Owners and Distribution Providers in NERC who yearly perform this benign maintenance activity on their battery systems while the Protection Systems that the station batteries support are in service.		
Ameren Services (1)	Ballot Comment - Affirmative	Clarify p17 Table 1-4(e) interval meaning. We think this means we need to verify the Station dc supply voltage on 12 calendar year interval if unmonitored, or no periodic maintenance if monitored as stated.
Response: Thank you for your comments. You are correct in your interpretation for Protection System dc supply used only for distribution breakers that are associated with UFLS, UVLS, or SPS, as stated in Table 1-4(e).		
Old Dominion Electric Coop. (4)	Ballot Comment - Affirmative	ODEC believes the standard is very close to being ready for approval. 1. In the Attachment A for the battery testing, you exempt the UFLS and UVLS equipment in tables and then include SPS batteries in the table with UFLS and UVLS. Either SPS should be associated with UFLS and UVLS and you need to add it to the previous tables or fix table 1(f). 2. Also, consider going to 4 calendar months instead of 3 calendar months for the battery maintenance requirements.
Response: Thank you for your comments. 1. Special Protection Systems are often a far more complex system which may comprise a combination of “transmission”, distribution, and generation components, and are often installed to prevent serious system problems. Therefore, the requirements for SPS equipment maintenance align with that for other generic Protection Systems. It is also notable that the legacy PRC-017-1 includes batteries within the list of components to be addressed. However, if the breaker is a distribution breaker that is associated with SPS but is not otherwise associated with generic Protection Systems, the extended interval in Table 1.4(e) applies. 2. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a “grace period” if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month.”		
Associated Electric Cooperative, Inc. (1)	Ballot Comment - Negative	AECI appreciates the effort by the drafting team. However, the 90 day inspections for batteries and communications circuits should be extended to 120 days to allow for a 30 grace period. Schedules would be set for every 90 days as what is required in this revision.
Response: Thank you for your comments. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of		

Organization	Yes or No	Question 1 Comment
unmonitored components. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a “grace period” if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month”		
Manitoba Hydro (1) (3) (5) (6)	Ballot Comment - Negative	1. Battery Check Interval Manitoba Hydro maintains our position that the 3 month battery check interval should be extended to 6 months. The 3 month interval is too frequent based on our experience and while IEEE SDT 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. With the 3 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. 2. Conductance Measurements Conductance measurement should be listed in Table 1-4 as an acceptable measurement method.
Response: Thank you for your comments. 1. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month”. 2. In section 15.4 of “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” the SDT answered a Frequently Asked Question explaining what cell/unit internal ohmic measurements are. Conductance by definition is an ohmic measurement and although not spelled out in the standard is listed in Table 1-4 because it is an ohmic measurement.		
Georgia Transmission Corporation	No	We need clarification on the UFLS or UVLS system Station DC Supply test. We trip the high side device (non-BES asset) for each of our distribution stations UFLS or UVLS schemes, not the individual distribution breakers. It is hard to distinguish what maintenance interval and maintenance activities we should engage for Station DC Supply test. Since the device is not a distribution breaker as mentioned in the Table 1-4 (a-f) we would be conservative and choose to perform maintenance at all our distribution stations with UFLS or UVLS schemes as per Table 1-4(a). Reading the statements in the Supplementary Reference and FAQ, we notice our devices perform similar functions as the distribution breakers. Reference pg 60 of Supp. Ref. and FAQ paragraph 4. Since tripping the high side device of a distribution transformer still constitutes a distributed system would our system meat the exclusion criteria although it is not a distribution breaker, would this meet the same requirements and exempt the station from Table 1-4(a) and require only maintenance for DC systems as per Table 1-4(e)? Please clarify. We recommend changing the term distribution breaker to distribution asset interruption device or non-BES equipment interruption device.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. Table 1-4 (e) has been modified in consideration of your comment to improve clarity (“non-BES interrupting devices “). If the cited distribution transformer is not a BES element, the Protection Systems for that distribution transformer are not included per the Applicability (4.2.1) as modified.		
PNGC Comment Group	No	We agree the changes to the tables have added clarity, but disagree with the maintenance intervals for DC supply. Comments: PNGC’s comment group views the Maximum Maintenance Interval for station DC Power Supply (Table -14a/b/c/d) to be unnecessarily onerous and restrictive to many smaller-rural entities, in the west and probably throughout the US, and this prevents us from being able to support PRC-005-2 as written. We make these comments with the understanding that others have made similar comments in the past but we feel strongly that this is an important issue worthy of further review by the SDT. We believe a quarterly inspection schedule can be met while at the same time allowing entities the flexibility they need. IEEE 1188-2005 suggests a quarterly inspection schedule for lead acid batteries and we believe the standard interval for verifying and inspecting dc supply should be 3 months with a maximum interval of 6 months. This meets the quarterly threshold and gives some flexibility to account for unusual conditions. There are substations in Pacific Northwest rural areas that can be inaccessible during long periods of time during the winter, potentially exposing an entity to sanction if weather conditions prevent access to equipment for an extended period of time. Additionally, due to a smaller workforces and greater distances between equipment subject to PRC-005, small-rural entities face obstacles that large entities may not have. The three month maximum interval assumes ideal conditions and resource access and is not realistic. We thank the SDT for considering our comments.
Response: Thank you for your comments. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a “grace period” if adequate program oversight is exercised, and disagrees that the intervals should be extended.		
Arizona Public Service Company	No	Although considerable clarity was achieved in the structuring of the table for the different types of technologies associated with the DC supply, there is issue on the maximum allowable intervals. The standard remains too prescriptive in the intervals and maintenance activities. As an example it is believed the intent of the interval for verifying voltages and inspecting electrolyte levels and unintentional grounds level would be every 3 months. However, for the entity to ensure compliance and not incur a violation it would have to have a shorter interval, probably every 2 months just to ensure compliance and not incur a violation. The 3 month interval is in question based on programs that have been in service for many years where four months have been proven as reliable for operation, an even shorter period than 3 or 4 months is not only a burden but an unnecessary expense without a benefit of increase reliability of the Bulk Electric System.

Organization	Yes or No	Question 1 Comment
Response: Thank you for your comments. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a "grace period" if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" for a discussion about "calendar month".		
Southern Company Generation (5)	Ballot Comment - Affirmative	The restructured Table for Station DC supply does clarify what is being required for each type of dc system, yet the Station DC Supply requirements, however, are excessively prescriptive in comparison to the other Protection System component types.
Response: Thank you for your comments. The SDT recognizes that Table 1-4 with its tables a through f is considerably larger than any of the tables for the other four Protection System components. However the SDT does not agree that the maintenance activities of Tables 1-4 (a –f) for the station dc supply are "excessively prescriptive." As pointed out in Section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" the station battery which is part of the station dc supply is unique from any other Protection System component in that it is a perishable product which requires several prescribed maintenance activities to monitor and maintain its ability to perform as designed for its life cycle.		
Indeck Energy Services	No	The tables are limited to a few battery technologies and will be out of date in short order with the many types of advanced batteries already on the market. The testing requirements should be performance based as opposed to prescriptive.
Response: Thank you for your comments. While the SDT agrees that there are a few advanced batteries and new station dc supplies which have non battery based energy storage devices in them on the market, the SDT disagrees that the testing requirements for batteries used in station dc supplies should be performance based as opposed to prescriptive. FERC Order 693 and the approved SAR assign the SDT to develop a standard with maximum allowable intervals and minimum maintenance activities. Please note that the Standard specifically addresses requirements for non-battery based energy storage devices within Table 1-4(d). According to the NERC Reliability Standard Development Process, NERC Reliability Standards must be reviewed at least once every five years, and any changes related to new technologies can be addressed within that process.		
Tampa Electric Company	No	If during a UF operation there were ever any breakers that did not trip properly, there may be enough that do trip to return things to balance. There is more room for error with UFLS than with BES. The standard does make some allowance for differences between UFLS equipment and BES equipment. For example the DC source testing requirement for UFLS is to just test the battery voltage when the control circuit is tested. It is not necessary that the breaker be tripped for UFLS testing every six years as is the case for BES. However, every 12 years all unmonitored control circuitry must be tested, which may include tripping the breaker.
Response: Thank you for your comments. Table 1-5 does not require tripping of the breaker for UFLS/UVLS.		
Tri-State G & T Association, Inc.	Ballot	On Page 19, Table 1-5, the standard requires that electromechanical lockout control circuits be maintained

Organization	Yes or No	Question 1 Comment
(3) (5)	Comment - Affirmative	every 6 years and protective function unmonitored control circuits be maintained every 12 years. Why is there inconsistency in the interval between the electromechanical lockout and protective function control circuits?
Response: Thank you for your comments. The circuit itself is 12-years, but the interval for electromechanical devices such as auxiliary or lockout relays remains at 6 years, as these devices contain “moving parts” which must be periodically exercised to remain reliable.		
Constellation Energy Commodities Group (6)	Ballot Comment - Negative	As with previous revisions of this standard, the maintenance intervals and activities described in Table 1-1 through Table 1-5 are too prescriptive.
Constellation Power Source Generation, Inc. (5)	Ballot Comment - Negative	CPG believes, as with previous revisions of this standard, that the maintenance intervals and activities described in Table 1-1 through Table 1-5 are too prescriptive.
Response: Thank you for your comments. The SDT is not prescribing or suggesting what methods an entity employs within their program. The intervals remain as prescribed within the standard and are designed to be clear and effective to support reliability of the BES.		
Alliant Energy Corp. Services, Inc. (4)	Ballot Comment - Negative	Table 1-5 (Component Type – Control Circuitry) Item 4 – “Unmonitored control circuitry associated with protective functions” require a 12 calendar year maximum maintenance interval. We believe UFLS and UVLS control circuitry should be exempted from this requirement. It would take multiple failures to have any impact, and the impact on the BES would be minimal.
Response: Thank you for your comments. The SDT disagrees; however, the requirements related to interrupting devices used only for UFLS/UVLS are less detailed than those for other Protection Systems because of the reason cited in your comment.		
Consumers Energy (4)	Ballot Comment - Negative	Relative to Table 1-5, the activities will likely require that system components be removed from service to complete those activities. In the case of system elements that do not have redundant protection systems (such as those related to lower-voltage systems within the BES), it may not be possible to do so with outaging customers for the duration of the maintenance activity. The standard must exempt these components from the activities of Table 1-5 if the activity would result in deenergizing customers.
Response: Thank you for your comments. The intervals and activities specified are believed by the SDT to be technically effective. It is left to the entity to determine how to align these requirements with requirements of other regulations and with operational concerns. Entities should be able to complete the activities within the shorter intervals without outages.		
American Transmission	Ballot	1. ATC recognizes the substantial efforts and improvements to PRC-005-2 that have been made and

Organization	Yes or No	Question 1 Comment
Company, LLC (1)	Comment - Negative	appreciate the dedicated work of the SDT. ATC appreciates the removal of Requirement R1.5 and R4 and other clarifications from draft 3. 2. ATC's remaining concerns to PRC-005-2 are with the 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. Note: Additional Comments to overall Standard also submitted.
Response: Thank you for your comments. 1. Thank you for your support. 2. The lockout relays and trip coils contain "moving parts" which must be periodically exercised to remain reliable. Operational results, if desired by an entity, MAY be used to meet maintenance requirements to the degree that they verify, etc, the relevant performance. Whether their use is effective for a specific entity is left to the entity to determine.		
Wisconsin Electric Power Co. (5) Wisconsin Electric Power Marketing (3) Wisconsin Energy Corp. (4)	Ballot Comment - Negative	Clarification is required in Table 1-5 as to what trip and control paths should be tested. Specifically, should non-protection paths, such as local control switches, that are not part of the Protection System, but operate Protection System Component, be tested? In Table 1-5, the maintenance activity for unmonitored control circuitry associated with protective functions is to "verify all paths of the control and trip circuits". We recommend that only the protection system paths of the control and trip circuits require verification by PRC-005-2.
Response: Thank you for your comments. The SDT believes that Protection Systems that protect BES elements should be included. This position is consistent with the currently-approved PRC-005-1 and consistent with the SAR for Project 2007-17. The header section of Table 1-5 has been modified to clarify that only the control circuitry associated with protective functions is being addressed.		
Kristina M. Loudermilk (8)	Ballot Comment - Affirmative	In table 1-5 is it necessary to mention the second and last item in the table. If there is nothing to do, then why have it as an attribute making it mandatory to keep track of, well, nothing. If those items do need to stay, then could we reorganize the table so where it is in ascending order from Maximum maintenance intervals, like the other tables?
Response: Thank you for your comments. The SDT believes that inclusion of these two items add clarity. The Table entry for trip coils associated only with UVLS/UVLS has been left in the original position to relate it directly to the companion activities for other applications.		

Organization	Yes or No	Question 1 Comment
Nebraska Public Power District	No	The restructured tables are indeed an improvement; however the tables still need some work for clarity: 1. Table 1-5: Unmonitored control circuitry has a maintenance activity of "Verify all paths of the control and trip circuits." The wording of "control and trip circuits" leads to circuit verification of more than just trip circuits. In fact multiple circuits would have to verified, such as station house load transfer schemes. Providing documentation to an auditor to prove all paths have been tested will be difficult and is considered excessive. The paperwork required to prove compliance is extremely excessive for this requirement and doesn't provide a benefit to reliability. 2. Table 1-5: Table 1-5 requires trip checking every six calendar years for trip coils and electromechanical lockout and/or tripping auxiliary devices. Every six years is excessive, when suitable monitoring is used. We recommend verification of these components be completed at the same frequency as the associated relay testing when monitoring is used. For electromechanical, no more than every 6 calendar years, for microprocessor, no more than 12 calendar years.
Response: Thank you for your comments. 1. The header section of Table 1-5 has been revised to clarify that it applies to "Control Circuitry Associated with Protective Functions", and the SDT believes that this revision addresses your concerns. 2. The electromechanical devices such as auxiliary or lockout relays remains at 6 years, as these devices contain "moving parts" which must be periodically exercised to remain reliable.		
Consolidated Edison Co. of New York (1) (3) (5)	Ballot Comment - Affirmative	1. We recommend increasing the Table 2 reporting window from 24-hours to 72-hours for facilities not continuously manned in order to accommodate discovery and reporting of failed alarms at these facilities which may occur over a long (3-day) holiday weekend.
Consolidated Edison Co. of New York (6)	Ballot Comment - Affirmative	1. We recommend increasing the Table 2 reporting window from 24-hours to 72-hours for facilities not continuously manned in order to accommodate discovery and reporting of failed alarms at these facilities which may occur over a long (3-day) holiday weekend. 2. We recommend that the drafting team recognize that a "fail safe" or "self-reporting" alarm design serves as an acceptable alternative to periodic testing. This "fail safe" or "self-reporting" alarm design is equivalent to continuous testing the alarm. When the alarm circuit fails the alarm is set to "alarm on" and automatically notifies the control center, initiating a corrective action.
Response: Thank you for your comments.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">1. The SDT believes that the monitoring and reporting will be generally done by automatic reporting methods such as SCADA and previously removed a reference to “automatic reporting” specifically to address those cases where the facility is manned.

2. The application discussed seems to the SDT to be an effective method of “monitoring the monitoring circuit”. (See Table 2, last row with heading “Alarm Path with monitoring.”)</td></tr>
<tr><td>Nebraska Public Power District</td><td>No</td><td>1. Table 2: The interrelationship between Tables 1-1 through 1-5 and Table 2 is ambiguous. Tables 1-1 through 1-5 “component attributes” columns references Table 2 in many cases as the criteria for maximum interval. However, each table entry has a maximum maintenance interval listed as well. There are a few instances where the “trump” interval is not clear. Table 1-5 is a good example.

2. Table 2 states that monitored devices (1-1 through 1-5) not having monitored alarm paths shall be tested every 12 years. However, Table 1-5 states that DC circuits with monitored continuity shall have no periodic maintenance. We suspect that Table 2 attributes needs further clarification to eliminate the confusion, both Table 2 attributes at first glance appear to say the same thing. However, after study it appears to address “detection” monitoring versus continuous (control center type) monitoring. We believe further distinguishing clarifications are needed to make it evident and clear.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

1. The SDT believes that the activities and intervals, as they relate to whatever monitoring attributes are present, are clear. Table 2 is specifically labeled to address whatever maintenance is necessary to the monitoring and alarming equipment itself. The references to Table 2 have been corrected where necessary.

2. Table 1 is related to the component itself, and Table 2 relates to maintenance of the monitoring and alarming if relevant. If the monitoring specified is present, no periodic maintenance of the control circuitry itself is needed. However, as indicated in Table 2, maintenance (or monitoring) is required to assure that the monitoring on the control circuitry is operational.</td></tr>
<tr><td>ExxonMobil Research and Engineering</td><td>No</td><td></td></tr>
<tr><td>Ameren</td><td>Yes</td><td>Please carry the grid across in Table 1-4(f) to show the Maintenance Activities that go with the Component Attribute.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The grid in Table 1-4(f) is drawn as the SDT intended, to show “No periodic maintenance specified” for all table entries. The activity listed is the activity that is being accomplished by the monitoring mechanism.</td></tr>
<tr><td>Tennessee Valley Authority</td><td>Yes</td><td>However, The requirement to perform battery cell internal ohmic measurements every 18 months for vented lead-acid batteries is excessive, and no technical justification is provided for an 18-month interval. A 3-year</td></tr>
</table>

Organization	Yes or No	Question 1 Comment
		internal ohmic test frequency is adequate to prove battery integrity. EEE 450 does not provide a recommended interval for internal ohmic measurements. For standard capacity testing, the recommended interval is no greater than 25% of expected battery life. Our normal battery life is 20+ years, so the recommended capacity test interval would be about 5 years. EPRI also recommends capacity testing at 5 year intervals. There is no justification for performing internal ohmic measurements every 18 months (which equals every 7.5% interval of the expected battery life). Recommendation: Set the interval for battery internal cell ohmic testing at 3 years.
Response: Thank you for your comments. The Maintenance Activity of evaluating the measured cell/unit internal ohmic values to station battery baseline is an optional activity to verify that the station battery can perform as designed. An owner who desires not to take internal ohmic measurements on a Vented Lead-Acid (VLA) battery can elect to verify that the station battery can perform as designed by conducting a performance, service, or modified performance capacity test of the entire battery bank without ever having to perform any internal ohmic measurement on the battery. The maximum maintenance interval for performing this capacity test on a VLA battery bank is 6 Calendar Years. In section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" - that was posted for review with PRC-005-2 - the SDT answered several Frequently Asked Questions which explain why the 18 month Maximum Maintenance Interval is justified rather than the 3 year frequency that is assumed by some to be adequate.		
Exelon	Yes	What kind of component we are talking about in table 1.4(d) "Station DC Supply using Non Battery Based Energy Storage" for switchyard in nuclear plants?
Response: Thank you for your comments. An example of a "station dc supply" component of this nature would be fuel cells. The SDT is aware that some entities are beginning to apply non-battery-based dc supplies, but we are unaware whether anyone is using these in switchyards for nuclear plants.		
Xcel Energy	Yes	Regarding the last row of Table 1-4(f): it seems very inconsistent to require a formal trending program for a manual 6 month (VRLA)/18 month (VLA) internal ohmic reading but to require no gathering and analysis of data as an alarm for a ohmic value for each cell/unit is available. If just a raw ohmic value is an adequate predictor of cell life, than why require a trending program for the manual reading if all that is needed to determine adequacy of remaining cell life is just a simple acceptance criteria (i.e. - alarm set point) against which you need to compare your measured data? In theory these are very gradual and predictable changes in ohmic readings over the entire life of the battery, such that the benefit of real time knowledge of exactly when a threshold is reached via alarm is minimal rather than having to wait until the next manual reading to ascertain that the threshold limit has been reached.
Response: Thank you for your comments. Your comment concerning the last row of Table 1-4(f) being inconsistent with the two distinct maintenance activities for internal ohmic value measurement found in the unmonitored station dc supply tables 1-4(a) and 1-4(b) was very incisive. As pointed out in section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" the SDT recognized that there are two maintenance activities in Table 1-4(b) which appear to be the same, but require a different method of interpretation to complete the required maintenance activity. The Drafting Team has considered your comment in light of its own discussion in the Supplementary Reference & FAQ document and has divided the last row of Table 1-4(f) into two rows to reflect the		

Organization	Yes or No	Question 1 Comment
two distinct maintenance activities required in the unmonitored tables (inspection of the condition of individual VRLA cell/units, and evaluating internal ohmic measurements to a baseline to verify the station battery can perform as designed).		
Duke Energy	Yes	We believe the table could be improved further to aid compliance by adding a footnote to the term "baseline" in the sub-tables 1-4(a), 1-4(b) and 1-4(f). The following proposed footnote text is taken from page 65 of the Supplementary and FAQ Reference Document: "Often for older VLRA batteries the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to. To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, all manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also several of the battery manufacturers have libraries of baselines for their products that can be used to trend to."
Response: Thank you for your comments. The addition that you suggest is properly considered application guidance; the SDT has been advised that such information is not to be included within the standard, and that it is appropriately included in separate reference materials.		
Ingleside Cogeneration LP	Yes	1. 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. 2. However, we have found that the remainder of the items in the Tables are logically organized and correspond effectively with the five components of a Protection System. The maintenance activities and intervals are technically solid and reasonable. In our opinion, the benefits to proceed outweigh our one concern with the validation of communications channel performance.
Response: Thank you for your comments. 1. We agree that it is not good practice to disturb fiber connections as you indicate. Draft 4 does not require that. The Entity must perform the activities in the "Maintenance Activities" column. The SDT does not interpret this as taking anything apart. 2. Thank you.		
Manitoba Hydro	Yes	The restructured tables are an improvement, but we suggest that conductance (siemens) should be listed as

Organization	Yes or No	Question 1 Comment
		an acceptable measurement in addition to the resistance measurements already included in the tables.
Response: Thank you for your comments. In section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" the SDT answered a Frequently Asked Question explaining what cell/unit internal ohmic measurements are. Conductance is an ohmic measurement and although not spelled out in the standard is listed in Table 1-4 because it is an ohmic measurement.		
NIPSCO	Yes	Sub-tables are good. A related question: Some devices such as reclosers and circuit breakers may include batteries within the device itself. Does Table 1-4 apply to such batteries and DC supply? Recloser batteries do not provide access to intercell connections.
Response: Thank you for your comments. In most instances Table 1-4 does not apply to recloser batteries or batteries within the device because they are not generally used to provide dc power to Protection Systems designed to provide protection for BES elements. However, these types of devices with self contained batteries may be used at the distribution level to provide Protection Systems used for underfrequency and undervoltage load-shedding. Maintenance activities and maximum maintenance intervals for such batteries are found in Table 1-4(e) of the Standard.		
MISO Standards Collaborators American Transmission Company, LLC	Yes	1. Yes, however, in the "Supplemental reference and FAQ" document on page 65 there are two areas of concern. Page 65, paragraph 4:" the type of test equipment used to establish the baseline must be used for any future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment." While we understand the importance of creating a baseline, it is not feasible to expect the test equipment be the same as the manufacturer's test equipment or even the same test equipment over the life of the battery. The expected life of a battery may be in excess of 20 years and it is not feasible to expect that the type of equipment will not change during this period. 2. On Page 65, paragraph 6, it states:"all manufacturers of internal ohmic measurement devices have established libraries of baseline values." We question the availability of baseline libraries for all manufacturers considering the variety and longevity of installations.
Response: Thank you for your comments. 1. The "Supplementary Reference and FAQ" concerning types of equipment have been changed per your suggestion to reflect consistent test data as opposed to exactly the same piece of test equipment. 2. Many manufacturers of "Ohmic" test equipment have established libraries of baseline data. You are correct that test equipment manufacturers may not have data on every battery in service today. Several manufacturers of batteries (not all) have libraries for some (but perhaps not all) of their products. To achieve significant results from a trending program one needs to have good baseline data. The "Supplementary Reference and FAQ" document has been revised to reflect your concern – the word, "all" was changed to "many".		

Organization	Yes or No	Question 1 Comment
MRO's NERC Standards Review Subcommittee	Yes	Yes, however, in the “Supplemental reference and FAQ” document on page 65 this is one area of concern. Page 65, paragraph 4 ”the type of test equipment used to establish the baseline must be used for any future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer’s equipment” While we understand the importance of creating a baseline, it’s not feasible to expect the test equipment to be the same as the manufacturer’s test equipment or even the same test equipment over the life of the battery. The expected life of a battery may be in excess of 15 years and it is not feasible to expect that the type of test equipment will not change during this period. We suggest changing the wording to read that consistent test equipment should be used to provide consistent/comparable results.
Response: Thank you for your comments. The statements concerning types of equipment have been changed per your suggestion to reflect consistent test data as opposed to exactly the same piece of test equipment.		
The Detroit Edison Company	Yes	Yes, the tables do provide more clarity. It is much easier to understand the requirements now that they are broken down by technology, and the exclusion of intervals on certain activities based on the individual monitoring attributes is helpful. I appreciate the thought that went into revising this.
Response: Thank you for your comments.		
New York Power Authority (1)	Yes	No comments.
ITC	Yes	The re-structured tables are easier to use.
Response: Thank you for your comments.		
Luminant	Yes	No comments.
BGE	Yes	No comments.
Luminant	Yes	No comments
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 1 Comment
Electric Market Policy	Yes	
Santee Cooper	Yes	
Bonneville Power Administration	Yes	
SPP reliability standard development Team	Yes	
Pepco Holdings Inc	Yes	
Imperial Irrigation District	Yes	
FirstEnergy	Yes	
Western Area Power Administration	Yes	
NextEra Energy	Yes	
Liberty Electric Power LLC	Yes	
FHEC	Yes	
Farmington Electric Utility System	Yes	
Central Lincoln	Yes	
Illinois Municipal Electric Agency	Yes	
Shermco Industries	Yes	
Dominion Virginia Power	Yes	

Organization	Yes or No	Question 1 Comment
American Electric Power	Yes	
CPS Energy	Yes	
US Army Corps of Engineers	Yes	
Alliant Energy	Yes	
GDS Associates	Yes	
Independent Electricity System Operator	Yes	
MidAmerican Energy Company	Yes	

2. The SDT has modified the Implementation Periods within the Implementation Plan. Do you agree with the changes? If not, please provide specific suggestions for improvement.

Summary Consideration: Most commenters who responded to this question agreed with the proposed Implementation Plan. There was no predominant theme in the comments. A few commenters focused on the perceived short time period allowed for the initial conversion and development of their maintenance program while and other commenters suggested specifying Jan. 1 as an interval marker to ease in calendar year interval determination.

The SDT believes that the time frames in the proposed Implementation Plan are adequate for conversion when considering the complete time frame that is likely to occur between industry approval vote and regulatory approvals.

The Implementation Plan was modified to provide for a lengthened implementation period for R1 and the less-than-1-calendar-year activities in R2 and R3 to allow entities not subject to regulatory approvals of 9 additional months following BOT approvals, and, for the remaining activities, of 12 additional months following BOT approvals, to be more consistent with the expected Regulatory Approval timelines. Additionally, all "calendar year" implementation periods were revised to "months" for additional clarity.

The team also clarified that during the phase-in of the requirements in PRC-005-2, entities must be prepared to identify whether each component is being maintained according to PRC-005-2, or according to PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0.

Under Item 4a, the team corrected the reference to generating plant outages to change "two years" to "three years" to align with the time allocated for becoming 30% compliant (3 years) with maintenance of components subject to a 6 year interval.

Organization	Yes or No	Question 2 Comment
Tri-State G&T		The draft standard requires the PSMP to include maintenance and testing intervals for Station DC supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply). Does this requirement include DC systems (batteries not included in station batteries) used by communication systems necessary for the correct operation of protective functions?
Response: Thank you for your comments. This comment does not apply to the Implementation Plan.		
Consumers Energy (4)	Ballot Comment - Negative	The implementation period for R1 and R3 for the component types addressed in Tables 1-3 and 1-5 is not adequate. The requirements may cause entities to identify components very differently than they are currently doing, and doing so may take several years to complete. The Implementation Plan for R1 and R3 is too aggressive in that it may not permit entities to complete the identification of discrete components and the associated maintenance and implement their program as currently proposed. We propose that the Implementation Plan specifically address the components in Table 1-3 and 1-5 with a minimum of 3 calendar

Organization	Yes or No	Question 2 Comment
		years for R1 and 12 calendar years after that for R4.
Response: Thank you for your comments. The SDT believes that the degree of flexibility written in the standard for categorizing (and subcategorizing) is sufficient for accomplishing the requirements within the time frames given in the Implementation Plan. For example, the voltage and current sensing devices may be individually identified or identified by group (associated with a relay). Examples of different ways to group the dc control circuitry discrete components include individual circuits, individual lockout devices, component protected, by control panel, or by station. The method chosen for the representation will impact the amount of time required to transform a maintenance program.		
Ameren Services (1)	Ballot Comment - Affirmative	PSMP Implement Date should commence at the beginning of a Calendar year (i.e., January 1st). This is the most practical way to transition assets from our existing PRC-005-1 plans
Response: Thank you for your comments. The SDT believes that the proposed Implementation Plan intervals are long enough to provide an entity the amount of time it will take to transition to the new intervals. Considering the additional time between an approved ballot by the industry through the NERC BOT approval and regulatory agency approval, it is very likely that an entity may have an additional 6-9 months to transition to the new program. The guidance provided to drafting teams by NERC suggests that standards should be effective at the beginning of a calendar quarter, rather than a calendar year.		
Independent Electricity System Operator	No	We commented on this before and we will comment again. The time periods for FERC-jurisdictional entities and non-jurisdictional entities should have at least a 3-month difference to allow some time for FERC approval after BoT adoption in an attempt to more or less put the effective dates of the two groups of entities in the same general time frame. The implementation plan as presented will always result in an effective date for the non-jurisdictional entities to be at least some months (the time between BoT adoption and FERC approval) earlier than their jurisdictional counterparts.
Response: Thank you for your comments. The Implementation Plan was modified to provide for a lengthened implementation period for R1 and the less-than-1-calendar-year activities in R2 and R3 to allow entities not subject to regulatory approvals of 9 additional months following BOT approvals, and, for the remaining activities, of 12 additional months following BOT approvals, to be more consistent with the expected Regulatory Approval timelines.		
NIPSCO	No	This new standard’s calibration intervals outlined here will require additional staff at our organization. In order to get people hired and trained the implementation plan should allow more time for the phase-in period. From experience, calibration should have been de-emphasized since more concerns are discovered during full tests.
Response: Thank you for your comments. The SDT believes that the proposed Implementation Plan intervals are long enough to provide an entity the amount of time it will take to transition to the new intervals. Considering the additional time between an approved ballot by the industry through the NERC BOT approval and regulatory agency approval, it is very likely that an entity may have an additional 6-9 months to transition to the new program.		

Organization	Yes or No	Question 2 Comment
Tampa Electric Company	No	The new maintenance plan has to be completed in 1 year. 1. Would that mean it is required to identify and list every element that requires testing in a database within the first year? This will be a time intensive effort that probably that would be difficult to complete in a year with current personnel. 2. After 1 year, would entities be required to start implementing the plan depending on the maintenance intervals of the equipment? Qualified people would have to be in place to start the work, again this would be difficult to accomplish with current personnel.
Response: Thank you for your comments. 1. No. Please read R1 carefully to determine what's necessary to be implemented. There is no requirement to have a database – just to have a PSMP that identifies the component "types" and for each component type, the associated type of maintenance program, associated maintenance activities, maintenance intervals, and, for component types that use monitoring to extend the intervals, the appropriate monitoring attributes. There is no requirement to identify and list every element. 2. Yes. The implementation of the plan must proceed as indicated.		
Indeck Energy Services	No	The last part of the implementation plan is vague, if not undefined. The implementation should "follow the previous maintenance intervals until all maintenance is transitioned to the new intervals."
Response: Thank you for your comments. The SDT presumes that your comment is related to the last paragraph of the General Consideration section of the proposed Implementation Plan. The entity should follow the previous maintenance intervals for any specific components until that component is addressed by PRC-005-2. As the transition is occurring, the entity should adjust its maintenance and testing schedule so that it is able to demonstrate that the required % of components meet the maintenance intervals given in the PRC-005-2 tables at each of the % compliant milestones given in this Implementation Plan.		
American Electric Power	No	On page 2 of the implementation plan, it is indicated that PRC-005-1, PRC-008-0, PRC-011-0 and PRC-017-0 shall be retired and that entities will be required to identify which components will be addressed under PRC-005-1 or PRC-005-2. There is no wording to cover those components that are still being addressed under PRC-008-0, PRC-011-0 or PRC-017-0 during the implementation period.
Response: Thank you for your comments. As noted in the "General Considerations", the entity should follow the previous maintenance intervals for any specific components until that component is addressed by PRC-005-2. As the transition is occurring, the entity should adjust its maintenance and testing schedule so that they are able to demonstrate that the required % of components meet the maintenance intervals given in the PRC-005-2 tables at each of the % compliant milestones given in this Implementation Plan. The team also clarified that during the phase-in of the requirements in PRC-005-2, entities must be prepared to identify whether each component is being maintained according to PRC-005-2 or according to PRC-005-1, PRC-008-0, PRC-011-0, or PRC-017-0.		

Organization	Yes or No	Question 2 Comment
Bonneville Power Administration	No	Many of the maintenance intervals in the standard are given in the terms calendar years or calendar months. There is no description of these terms in the NERC Glossary. My Webster's dictionary defines calendar year as the period that begins on January 1 and ends on December 31. There is no definition in my dictionary of calendar month. Is the intent of the term calendar year in the standard that maintenance intervals start on January 1 and end on December 31? This would make all maintenance due on December 31, and December would be a very busy time. Does this mean that if I do maintenance on something with a maximum interval of six calendar years in June of 2011 that it will be due again on January 1 of 2017 instead of June 1 of 2017? We believe that the drafting team intends for maintenance to be due after a given number of years that begins to elapse immediately after the previous maintenance is completed so that in the previous example the maintenance would be due on June 1, 2017. Please remove the word calendar from the maximum maintenance intervals to remove this confusion.
Response: Thank you for your comments. The intent of the term calendar year is to indicate that the maintenance is due sometime during a particular calendar year (Jan-Dec). If you perform maintenance in June 2011 and have a 6 calendar year interval, then the same maintenance is again due sometime in 2017 (2011 + 6). The NERC Compliance Application Notice CAN-0010, posted 19 Apr 2011, supports this compliance guideline. An interval of one calendar year means that the activity or event must be conducted at least once within each calendar year.		
FHEC	No	Can't locate the implementation plan in the posted materials.
Response: Thank you for your comments. The implementation plan was provided as a separate document within the posting and is available in the Standards Under Development section of the NERC website under Project 2007-17: http://www.nerc.com/filez/standards/Protection_System_Maintenance_Project_2007-17.html		
FirstEnergy	No	Although we agree with the timeframes being afforded to achieve compliance, we suggest the following changes: 1. During the last comment period, we suggested changes to the wording regarding retirement of existing standards on page 2. We do no see a response to these comments. Therefore, we would like to reiterate that the four existing standards are to be retired upon the effective date of the new standard and not upon regulatory approval. 2. In 4a of the plan, since the timeframe for 30% completion is 3 calendar years, we suggest a change to three calendar years for the parenthetical phrase “(or, for generating plants with scheduled outage intervals exceeding two calendar years, at the conclusion of the first succeeding maintenance outage)”. Change ”two” to “three” 3. We suggest the implementation plan be included within the body of the standard. It is very burdensome for

Organization	Yes or No	Question 2 Comment
		entities to have to look for the implementation plan and we believe that a “one-stop shopping” approach would alleviate this burden.
Response: Thank you for your comments. 1. The Effective Date within the Standard was stated as it is based on verbal advice of NERC Compliance – several drafts ago. 2. The Implementation Plan has been modified as you suggested. 3. The Implementation Plan is provided separately in accordance with instructions from the NERC Standards Department and Standards Committee. Further, at the end of all transition periods, it is not needed in the standard.		
ExxonMobil Research and Engineering	No	
Ameren	Yes	While we agree with the Implementation Periods, it would be best to alter R2 and R3 implementation such that components with maximum allowable intervals of 1 year or longer align with a true calendar year (i.e. begin with January 1).
Response: Thank you for your comments. The SDT believes that the proposed Implementation Plan intervals are long enough to provide an entity the amount of time it will take to transition to the new intervals. Considering the additional time between an approved ballot by the industry through the NERC BOT approval and regulatory agency approval, it is very likely that an entity may have an additional 6-9 months to transition to the new program. The guidance provided to drafting teams by NERC suggests that standards should be effective at the beginning of a calendar quarter, rather than a calendar year.		
MidAmerican Energy Company	Yes	1. 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. 2. In addition, it would seem appropriate to allow entities that decide to implement PRC-005-2 requirements

Organization	Yes or No	Question 2 Comment
		before the standard becomes effective to count the maintenance they do before the effective date in the implementation plan schedule and in the testing interval compliance.
Response: Thank you for your comments. 1. The Implementation Plan establishes that an entity must follow its current plan until the new standard is implemented for any specific component. Therefore, an entity should have documentation that it has maintained any given component according to its current program until it is addressed in the revised program (including all relevant activities addressed in PRC-005-2). An entity should adjust it's maintenance and testing schedule so that it is able to demonstrate that the required % of components meet the maintenance intervals given in the PRC-005-2 tables at each of the % compliant milestones given in the Implementation Plan. The team also clarified that during the phase-in of the requirements in PRC-005-2, entities must be prepared to identify whether each component is being maintained according to PRC-005-2 or according to PRC-005-1, PRC-008-0, PRC-011-0, or PRC-017-0. 2. If entities begin to implement the PRC-005-2 activities before the effective date, it seems to the SDT that this entity will find that they it has fully implemented PRC-005-2 sooner, and will thus have attained a stable sustainable program that much sooner.		
New York Power Authority (1)	Ballot Comment - Affirmative	2. The SDT has modified the Implementation Periods within the Implementation Plan.. Do you agree with the changes? If not, please provide specific suggestions for improvement. X0 Yes 0 No Comments:
Luminant	Yes	No comments.
BGE	Yes	No comments.
Luminant	Yes	No comments
Northeast Power Coordinating Council	Yes	
MISO Standards Collaborators	Yes	
Electric Market Policy	Yes	
Santee Cooper	Yes	

Organization	Yes or No	Question 2 Comment
SPP reliability standard development Team	Yes	
Pepco Holdings Inc	Yes	
Tennessee Valley Authority	Yes	
Imperial Irrigation District	Yes	
PNGC Comment Group	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
The Detroit Edison Company	Yes	
Western Area Power Administration	Yes	
NextEra Energy	Yes	
Arizona Public Service Company	Yes	
Liberty Electric Power LLC	Yes	
Ingleside Cogeneration LP	Yes	
Farmington Electric Utility System	Yes	
Duke Energy	Yes	
Central Lincoln	Yes	
Illinois Municipal Electric Agency	Yes	

Organization	Yes or No	Question 2 Comment
Manitoba Hydro	Yes	
Shermco Industries	Yes	
Dominion Virginia Power	Yes	
CPS Energy	Yes	
US Army Corps of Engineers	Yes	
Alliant Energy	Yes	
Georgia Transmission Corporation	Yes	
American Transmission Company, LLC	Yes	
GDS Associates	Yes	
ITC	Yes	
Xcel Energy	Yes	

3. The SDT has modified the VSLs, VRFs and Time Horizons with this posting. Do you agree with the changes? If not, please provide specific suggestions for improvement.

Summary Consideration: Many commenters pointed out an error (which was corrected by the SDT) within the VSL for R2, where the Lower and High VSLs contained identical text.

Many comments were offered on the VRFs that demonstrated unfamiliarity with the relationship between VSLs and VRFs. Violation Risk Factors identify the reliability-related risk associated with non-compliance; VSLs are applied after a finding of non-compliance to identify the degree of non-compliance.

Many duplicate comments were offered on the content of the standard which were not relevant to the VRFs, VSLs, or Time Horizons and these were answered elsewhere in this document

VSLs for R1:

- Phased VSLs were added to address R1 Part 1.1, which was previously addressed only as a "Severe" VSL.
- A reference was added within the R1 VSL to Part 1.3.
- R1 High VSL was revised to add a reference to Table 2.

VSLs for R2:

- One element of the R2 VSL was made binary (Severe), rather than "phased" (in two steps), in response to several comments.

VSLs for R3:

- The R3 VSLs were revised to replace "complete" with "implement and follow" for consistency with the Requirement.

Other minor editorial changes were made throughout the VSLs in response to comments.

Organization	Yes or No	Question 3 Comment
Tri-State G&T		On Page 19, Table 1-5, the standard requires that monitored electromechanical lockouts be maintained every 6 years. Why is there inconsistency in the interval between the monitored lockouts and monitored relays?
Response: Thank you for your comments. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to your comments on the standard provided elsewhere in this report.		

Organization	Yes or No	Question 3 Comment
SPP reliability standard development Team	No	1. If the maintenance is done prior to the maximum interval would it then reset the clock. Or should it read that maintenance and testing should be done at least once per quarter etc. 2. We would like to see the plan split up into generation time horizons and transmission time horizons, these can be significantly different.
Response: Thank you for your comments. 1. Provided that all required maintenance activities are done, the activity for that interval is taken care of, and the clock is reset. 2. The options for the Time Horizons are "Long-term Planning" (a planning horizon of one year or longer), "Operations Planning" (operating and resource plans from day-ahead up to and including seasonal), "Same Day Operations" (actions required within the timeframe of a day, but not real-time), "Real-time Operations" (actions required within one hour or less to preserve the reliability of the bulk electric system), and "Operations Assessment" (follow-up evaluations and reporting of real time operations). All of the requirements are properly assigned a Time Horizon of "Long Term Planning". There is no provision for different Time Horizon between entity types.		
Indeck Energy Services	No	1. The VSL's for R1 should combine the ones for Lower, Moderate and High VSL into Lower VSL. The Severe VSL should be moved to the Moderate VSL. Because R1 is administrative, it shouldn't have High or Severe VSL's. 2. The R2 High VSL (3 yrs) is more stringent than the Severe VSL (5 yrs). 3. The R3 VSL's need to have combined numbers of components or percentages because small generators may only have 25 relays or 1 battery and would be categorized as High or Severe VSL with a few components affected. The percentage could apply to RE's with more than 250 components included in the PSMP. 4. The Medium VRF for R1 should be Low VRF because R1 is administrative. Only the performance of the maintenance has anything more than Low VRF. 5. The Medium VRF for R2 is OK. 6. Having a High VRF for R3 is without basis. R3 should have Medium VRF.
Response: Thank you for your comments. 1. R1 is not administrative – it is foundational to developing the program. The VSLs as established conform to the NERC Violation Severity Level Guidelines. 2. The SDT disagrees. R2 "High" reflects a failure to return the "Countable Events" to an acceptable level in three years. R2 "Severe" reflects even worse performance, in that the entity has failed to return the "Countable Events" to an acceptable level in an even longer period – five years.		

Organization	Yes or No	Question 3 Comment
3. The SDT disagrees. A smaller entity will have less to maintain in accordance with the standard, and thus the percentages are still appropriate. 4. R1 is not administrative – it is foundational to developing the program, and not having a program could "directly and adversely affect the electrical state or capability of the bulk electric system, or the ability to effectively monitor, control, or restore the bulk electric system" as established in the criteria for a Medium VRF, even if the devices are being maintained to some degree. Without having an established program, the remaining requirements are far less meaningful. 5. Thank you. 6. The SDT believes that failure to maintain Protection Systems could "place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures" as established in the criteria for a High VRF. This concern is borne out by observations relating to several disturbances over the last several years. Also, a High VRF for R3 is consistent with the PRC-005-1 VRF for the corresponding requirement (R2).		
FRCC (10)	Non-binding Poll Comment	The VSL's need additional work. Here are some of the issues I see: 1. For R1, the High VSL has a condition that states "Failed to include all maintenance activities or intervals relevant for the identified monitoring attributes specified in Tables 1-1 through 1-5. (Part 1.4)" This condition is really a combination of what is required in Part 1.3 AND Part 1.4. How would the compliance enforcement determine an appropriate VSL if the registered entity only did not do Part 1.3 (maintenance activities)? These should be separated. 2. Also the Severe VSL is also identified for failure to specify three or more component types. I believe it is more appropriate to have three in High VSL and leave the Severe VSL for 4 or more. 3. For R2, the Lower VSL lists item 1) as "Failed to reduce countable events to less than 4% within three years." This is also the same condition that is identified for the High VSL. It is also the same condition that is listed as item 2) for the Severe VSL. In Lower and Severe, the items are separated by OR so they are each distinct. So, which VSL should the compliance enforcement authority use? 4. Also for R2, Lower VSL is indicated for failure to document for countable events for 5% or less of components. Then you jump to Severe VSL for over 5%. That seems like a very huge jump. The Moderate and High VSLs should be used to make a more gradual difference. 5. Finally, for R2, the Lower VSL is indicated if a segment has 54-59 components and a Severe is more than 54 components. In reading Attachment A, it states that a segment MUST contain at least sixty (60) individual components. This would appear to me to be all or nothing. I would suggest that the only VSL for this would be a Severe if it did not have 60 or more.
Response: Thank you for your comments.		

Organization	Yes or No	Question 3 Comment
1. The SDT disagrees. For the assessment of compliance to R1, Part 1.3 and Part 1.4 work together in the fashion identified in the VSL. 2. The SDT disagrees, and believes that failure to address three or more component types (out of a total of five) indeed reflects a Severe violation of the requirement. 3. Thank you for catching this. The High VSL has been modified from three years to four years. Where elements of the VSL are separated by "or", the compliance enforcement authority should use each of them as appropriate. 4. The SDT disagrees. The documentation of countable events is so fundamental to a performance-based maintenance program that the SDT has assigned a Lower VSL to minor transgressions, with all other transgressions being regarded as a Severe VSL. 5. The SDT has modified the R2 VSL for the segment population to be binary as you suggested.		
Tri-State G & T Association, Inc. (3) (5)	Ballot Comment	1. On Page 7, R2 Violation Severity Levels, "Entity has Protection System elements in a performance-based PSMP but has failed to reduce countable events to less than 4% within three years" is shown as both a Lower VSL and a High VSL. What differentiates the two VSLs? 2. R1 VSL - Second item in Severe VSL is not addressed in any lower VSL. Should there also be a comparable violation in Lower and Moderate?
Response: Thank you for your comments. 1. Thank you for catching this. The High VSL has been modified from three years to four years. 2. VSLs have been added to Moderate and High to address lesser violations.		
Tri-State G & T Association Inc. (3)	Non-binding Poll Comment	1. Comment 1: On Page 7, R2 Violation Severity Levels, "Entity has Protection System elements in a performance-based PSMP but has failed to reduce countable events to less than 4% within three years" is shown as both a Lower VSL and a High VSL. What differentiates the two VSLs? 2. Comment 2: R1 VSL - Second item in Severe VSL is not addressed in any lower VSL. Should there also be a comparable violation in Lower and Moderate?
Response: Thank you for your comments. 1. Thank you for catching this. The High VSL has been modified from three years to four years. 2. VSLs have been added to Moderate and High to address lesser violations.		
Tri-State G & T Association Inc. (5)	Non-binding Poll	1: On Table 1-2, page 11: The standard describes the following component attributes, "Any unmonitored communications system necessary for correct operation of protective functions, and

Organization	Yes or No	Question 3 Comment
	Comment	not having all the monitoring attributes of a category below." How does this apply to redundant communication systems? If the primary communications channel fails the protective relay automatically fails over to the back-up channel and continues to function properly. Are redundant communication channels excluded from this component attribute and associated interval? Also, if a relay is set to operate in a manner typical when communication is not used for protection (i.e. defaulting to step-distance functions with a loss of communication), is the defaulted operation of the relay considered "correct operation" thereby excluding the communication as necessary for its correct operation? Please clarify the term correct operation and how it applies to redundant communication systems and/or the performance of the relay in the absence of communication. 2: The draft standard requires the PSMP to include maintenance and testing intervals for Station DC supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply). Does this requirement include DC systems (batteries not included in station batteries) used by communication systems necessary for the correct operation of protective functions? 3: On Page 19, Table 1-5, the standard requires that electromechanical lockout control circuits be maintained every 6 years and protective function unmonitored control circuits be maintained every 12 years. Why is there inconsistency in the interval between the electromechanical lockout and protective function control circuits? 4: On Page 7, R2 Violation Severity Levels, "Entity has Protection System elements in a performance-based PSMP but has failed to reduce countable events to less than 4% within three years" is shown as both a Lower VSL and a High VSL. What differentiates the two VSLs?
Response: Thank you for your comments. 1. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to your comments on the standard provided elsewhere in this report. 2. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to your comments on the standard provided elsewhere in this report. 3. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to your comments on the standard provided elsewhere in this report. 4. Thank you for catching this. The High VSL has been modified from three years to four years.		
Farmington Electric Utility System	No	VSL on R2: Lower criteria item 1; the wording is identical High VSL. FEUS recommends keeping the criteria in the Lower VSL.

Organization	Yes or No	Question 3 Comment
City of Farmington (3)		
Response: Thank you for your comments. Thank you for catching this. The High VSL has been modified from three years to four years.		
Alliant Energy Corp. Services, Inc. (4)	Non-binding Poll Comment	The Lower and High VSL for Requirement 2 have the same description. The Lower VSL has other possible items, but there is a conflict where an entity could argue for both a Lower and High VSL. That needs to be clarified.
Response: Thank you for your comments. Thank you for catching this. The High VSL has been modified from three years to four years.		
GDS Associates	No	1. Suggest clarification of the VSL for R2. It appears that R2 Lower VSL is also contained in the R2 High VSL. 2. If the maintenance is completed prior to the maximum interval, would it then reset the clock? Or should it read that maintenance should be done at least once per quarter? 3. The plan should split into generation time horizons and transmission time horizons since these can be significantly different
Response: Thank you for your comments. 1. Thank you for catching this. The High VSL has been modified from three years to four years. 2. Yes – it would reset the clock, provided that all required activities are completed during the performance of the maintenance. 3. The SDT disagrees. The options for the Time Horizons are “Long-term Planning” (a planning horizon of one year or longer), “Operations Planning” (operating and resource plans from day-ahead up to and including seasonal), “Same Day Operations” (actions required within the timeframe of a day, but not real-time), “Real-time Operations” (actions required within one hour or less to preserve the reliability of the bulk electric system), and “Operations Assessment” (follow-up evaluations and reporting of real time operations). All of the requirements are properly assigned a Time Horizon of “Long Term Planning”. There is no provision for different Time Horizon between entity types.		
Alabama Power Company (3) Georgia Power Company (3) Gulf Power (3) Mississippi Power (3)	Non-binding Poll Comment	But only if the clean version on Page 7 under Violation Severity Levels R2/High VSL match the redline dated 4/12/2011. Entity has Protection System elements in a performance-based PSMP but has failed to reduce countable events to less than 4% within four years.
Response: Thank you for your comments. The clean version represents the content desired for the Standard. The red-line is affected by peculiarities of		

Organization	Yes or No	Question 3 Comment
the red-lining tool within Microsoft Word.		
Tampa Electric Company	No	VSL is severe for more than 4% Countable Events on R2. It does not seem feasible.
Response: Thank you for your comments. R2, by reference to Attachment A, requires that entities using performance-based maintenance reduce Countable Events to less than 4% within three years. The R2 Severe VSL reflects failure to do so within five years.		
Manitoba Hydro	No	1. VSL for Requirement 2:-Needs to use consistent terminology. The standard requirements refer to components and component types, not elements. 2. The violation “Entity has Protection System elements in a performance-based PSMP but has failed to reduce countable events to less than 4% within three years” appears in both the Lower VSL column and the High VSL column. The violation cannot be both Lower and High. VSL for Requirement R3: -Suggested wording “completed its scheduled program”.
Manitoba Hydro (1) (3) (5) (6)	Non-binding Poll Comment	Manitoba Hydro is voting negative for the following reasons: 1. VSL for Requirement 2: -Needs to use consistent terminology. The standard requirements refer to components and component types, not elements. 2. The violation “Entity has Protection System elements in a performance-based PSMP but has failed to reduce countable events to less than 4% within three years” appears in both the Lower VSL column and the High VSL column. The violation cannot be both Lower and High. 3. VSL for Requirement R3: -Suggested wording “completed its scheduled program”.
Response: Thank you for your comments. The term, “element” is not used in any of the VSLs. 2. Thank you for catching this. The High VSL has been modified from three years to four years. 3. The SDT disagrees; the VSL address failure to complete the scheduled program. The suggested change does not reflect this.		
Duke Energy	No	Typographical error - the High VSL for R2 has been incorrectly changed to “within three years” from “within four years”. This is now the same as the Lower VSL.
Duke Energy	Non-binding Poll	There is a typographical error on the High VSL for R2. It has been incorrectly changed to “within three years” from “within four years”. This is now the same as the Lower VSL.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td>Comment</td><td></td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Thank you for catching this. The High VSL has been modified from three years to four years.</td></tr>
<tr><td>Kristina M. Loudermilk</td><td>Non-binding Poll Comment</td><td>1. In VSL R2 I find it confusing for the Lower VSL and High VSL. In the Lower VSL for R2 #1 is mentioned, but again mentioned in High VSL. IS there an easier way to make that flow?
2. Also I found that I have forgotten a comment for the Standard itself.... In Attachment A, #5 is mentioned twice. I understand as to why, so I think, but in the "To Maintain" #5 says that one has to use the prior year's data. It matches the exact form of "how to establish the performance based PSMP". I find this confusing. So does this mean that testing will be once a year for parts of the segment. I did not get that same understanding from the support documents. Is there way to reword one of the #5's to show case a difference. Or is this on purpose? I just found it confusing.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
1. The High VSL has been modified from three years to four years.
2. The “first” #5 applies to establishing the performance-based program; the “second” one – now modified to be #4 in the second section, applies to maintaining the performance-based program on a continuing basis.</td></tr>
<tr><td>Alliant Energy</td><td>No</td><td>The LOW and HIGH VSL for R2 are the same. There are additional possibilities for the LOW, but it is possible to be in both the LOW and HIGH VSL at the same time. We recommend removing #1 in the LOW VSL category to resolve the issue.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Thank you for catching this. The High VSL has been modified from three years to four years.</td></tr>
<tr><td>The Detroit Edison Company</td><td>No</td><td>R2 - It appears that the Lower VSL point 1) and High VSL are identical.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Thank you for catching this. The High VSL has been modified from three years to four years.</td></tr>
<tr><td>Consolidated Edison Co. of New York (1) (3) (5) (6)</td><td>Ballot Comment - Affirmative</td><td>Clarification is needed to assure that the industry more fully understands how the percentage of “maintenance correctable issues” will be computed in the R3 VSL.</td></tr>
<tr><td>Consolidated Edison Co. of New York (1) (5) (6)</td><td>Non-binding Poll</td><td>1: Clarification is needed to assure that the industry more fully understands how the percentage of “maintenance correctable issues” will be computed in the R3 VSL.</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td>Comment</td><td>2: We recommend increasing the Table 2 reporting window from 24-hours to 72-hours for facilities not continuously manned in order to accommodate discovery and reporting of failed alarms at these facilities which may occur over a long (3-day) holiday weekend.

3: We recommend that the drafting team recognize that a “fail safe” or “self-reporting” alarm design serves as an acceptable alternative to periodic testing. This “fail safe” or “self-reporting” alarm design is equivalent to continuous testing the alarm. When the alarm circuit fails the alarm is set to “alarm on” and automatically notifies the control center, initiating a corrective action.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

1. The SDT believes that this is clear; if an entity has 20 maintenance-correctable issues and has failed to initiate resolution of one, it has failed to initiate resolution of 5% of the maintenance-correctable issues.

2. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to your comments on the standard provided elsewhere in this report.

3. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to your comments on the standard provided elsewhere in this report.</td></tr>
<tr><td>Independent Electricity System Operator

Independent Electricity System Operator (2)</td><td>No

Non-binding Poll Comment</td><td>(1) We do not agree 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 suggest that the VRF for R3 be changed to Medium.

(2) The Severe VSL for R2 is improper. First, the reference to R3 is incorrect. Second, the first condition that says: “Failed to establish the entire technical justification described within R3 for the initial use of the performance-based PSMP” introduces a requirement not stipulated in R2 itself. We suggest to remove this condition. If the SDT feels strongly that the technical justification (we’re not sure what exactly it is) needs to be established for the initial use of the performance-based PSMP, then R2 should be revised to capture this requirement.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

1. The SDT believes that failure to maintain Protection Systems could “place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures” as established in the criteria for a High VRF. This concern is borne out by observations relating to several disturbances over the last several years. However, even if the program is not fully documented per R1 and R2, devices may still be maintained; thus the reduced VRF for these requirements. Also, the R3 “High” VRF is consistent with the VRF assigned to the similar PRC-005-1 requirement (R2).</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
2. The Severe VSL for R2 has been corrected to refer to R2. The remainder of the Severe VSL for R2 is correct, in that R2 itself specifies that the procedure in Attachment A must be used, both to establish and maintain a performance-based maintenance program. The definition of maintenance correctable issue has been revised to be clearer.		
Tennessee Valley Authority	No	TVA has 590 Pilot Relay (Carrier Blocking) Terminals that are tested twice a year. After an extensive study of carrier failures over a 5-year period, it was determined that we were not having any failures that could have been prevented by a functional test. In January 2008, we reduced our frequency from 4 times per year to 2 times per year. The failure rate has remained about the same since that change. As PRC 005-2 currently states, the PM frequency would be 3 months. Allowing for a one-month grace period would actually require the interval to be set at 2 months. Therefore, the interval we used prior to 2008 (4 times per year) still would not make TVA compliant with the stated 3 month interval.TVA Power Control Systems is in the process of developing extensive PM tests for carrier terminals to complement the existing PM program. This PM would record signal levels, reflected power, line losses, and other pertinent data. It is my position that this PM will improve reliability more than increasing the frequency of the functional test.
Response: Thank you for your comments. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to your comments on the standard provided elsewhere in this report.		
American Electric Power	No	This standard encompasses a very broad range of component types and functionality. It also encompasses 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.
Response: Thank you for your comments. The NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. The NERC VRF Guidelines establish the criteria for assigning VRFs and do not provide for multiple VRFs for a single requirement, and the percentages (where used) assigned within the VSLs conform to the criteria established within the NERC VSL guidelines.		
FHEC	No	For Distribution Provider level equipment there should be no High or Severe VSLs
Response: Thank you for your comments. The SDT disagrees; the VSLs are intended to address the degree to which an entity fails to comply with each requirement, and the nature of the entity has no bearing on this determination.		

Organization	Yes or No	Question 3 Comment
Pepco Holdings Inc	No	1. Are the bullet items listed for the R2 Severe Violation Severity Level , Item 5 an "and" or an "or"? 5) Failed to: • Annually update the list of components, • Perform maintenance on the greater of 5% of the segment population or 3 components, • Annually analyze the program activities and results for each segment. 2. The wording of the R3 Lower Violation Severity Level seems to imply that an entity that fails to complete 0% (i.e., completes 100%) of its maintenance correctable issues is non-compliant. Entity has failed to complete scheduled program on 5% or less of total Protection System components. OR Entity has failed to initiate resolution on 5% or less of identified maintenance correctable issues. The following re-phrasing is suggested: Entity has failed to complete scheduled program on greater than 0%, but no more than 5% of total Protection System components. OR Entity has failed to initiate resolution on greater than 0%, but less than or equal to 5% of identified maintenance correctable issues.
Response: Thank you for your comments. 1. The VSL has been modified to separate these items with “or”. 2. The SDT disagrees; this description conforms to the guidance in the NERC VSL Guidelines, and VSLs only apply if there is a failure to comply with the relevant requirement.		
Liberty Electric Power LLC (5)	Non-binding Poll Comment	The use of percentages, without accounting for the size of the entity, unfairly burdens small IPPs.
Response: Thank you for your comments. The SDT disagrees. A smaller entity will have less to maintain in accordance with the standard, and thus the percentages are still appropriate.		
Liberty Electric Power LLC	No	See comments at end.
Response: Thank you for your comments. Please see our response to your other comments.		

Organization	Yes or No	Question 3 Comment
ExxonMobil Research and Engineering	No	
Consumers Energy (5)	Non-binding Poll Comment	see comment on R3
Response: Thank you for your comments. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to your comments on the standard provided elsewhere in this report.		
New York Power Authority (1)	Yes	No comments.
Luminant	Yes	No comments.
BGE	Yes	No comments.
Luminant	Yes	No comments
Northeast Power Coordinating Council	Yes	
MISO Standards Collaborators	Yes	
Santee Cooper	Yes	
Imperial Irrigation District	Yes	
PNGC Comment Group	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
FirstEnergy	Yes	

Organization	Yes or No	Question 3 Comment
Western Area Power Administration	Yes	
NextEra Energy	Yes	
Ingleside Cogeneration LP	Yes	
Central Lincoln	Yes	
Shermco Industries	Yes	
CPS Energy	Yes	
US Army Corps of Engineers	Yes	
Ameren	Yes	
Georgia Transmission Corporation	Yes	
ITC	Yes	
MidAmerican Energy Company	Yes	
Xcel Energy	Yes	
NIPSCO		no comments at this time
Northern Indiana Public Service Co. (3)	Non-binding Poll Comment	One of our concerns is that, while the present standard is 2 pages and is the most highly violated and fined standard, the new proposed standard is 22 pages, the implementation plan is 4 pages and the Supplemental FAQ document is 87 pages.
Response: Thank you for your comments. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our		

Organization	Yes or No	Question 3 Comment
response to NIPSC's comments on the standard provided elsewhere in this report.		
Public Utility District No. 2 of Grant County	Non-binding Poll Comment	GCPD has made it a practical practice of not voting affirmative for VRF and VSL until the standard is edited to our satisfaction and can vote affirmative on the standard.
Response: Thank you for your comments. Please see the revisions made to the standard and the drafting team's responses to the comments.		
Florida Municipal Power Agency (4) (5) FMPP (6)	Non-binding Poll Comment	· Section 4.2.1 states that the Standard is applicable to "Protections Systems designed to provide protection BES Elements." Section 15.1 of the Supplementary Reference Document defines the scope as those "devices that receive the input signal from the current and voltage sensing devices and are used to isolate a faulted element of the BES." These two statements are not exactly equivalent, and in fact, are in conflict with the Interpretation of PRC-004-1 and PRC-005-1 for Y-W Electric and Tri-State, Approved by the Board of Trustees on February 17, 2011. Section 4.2.1 should be changed to "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." · Examples #1, #2 and #3 in Section 7.1 of the Supplementary Reference all indicate that it is a requirement to "verify all paths of control and trip circuits" every 12 years. As stated, there would be circuits included in the testing requirement that the SDT did not mean to include in the scope of the Standard (e.g., SCADA closing circuit.) The statements in the illustrative examples should be changed to "verify all paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices" to be in line with the definition of a Protection System. · Section 15.5 of the Supplementary Reference Document states: "It was the intent of this Standard to require that a test be made of any communications-assisted trip scheme regardless of the vintage of the technology. The essential element is that the tripping (or blocking) occurs locally when the remote action has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted". The SDT should reword this statement recognizing that tests performed on communication systems may not be performed at the same time an entity chooses to perform trip tests on the associated breaker(s). The notion of "overlapping" can be applied, for instance, by taking an outage on one relay set in a fully redundant system, initiating a trip signal from the remote end and observing

Organization	Yes or No	Question 3 Comment
		the trip signal locally. All remaining portions in the local communication-assisted trip paths can then be tested when the local line panel is taken out of service for maintenance.
Response: Thank you for your comments. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to the same comments on the proposed standard provided elsewhere in this report.		
Seattle City Light (5)	Non-binding Poll Comment	Pursuant to the negative ballot relating to the Standard. Both votes will be affirmed if the comments are addressed.
Response: Thank you for your comments. Please see the drafting team's responses to the comments offered by Seattle on the proposed standard.		
Seattle City Light (6)	Non-binding Poll Comment	Seattle City Light (SCL) commends the Standard Drafting Team (SDT) for the many improvements in the latest draft of proposed standard PRC-005-2. The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. Each draft has been better than that preceding, and the supporting material is very helpful in understanding the impact and implementation of the proposed Standard. However, SCL votes NO for this draft because of 1) the inclusion and treatment of electromechanical lockout relays within the scope of draft Standard and 2) confusion about language between section 4.2 and Requirement 1. Regarding electromechanical lockout relays, SCL is highly concerned about the reliability risks and logistical difficulties associated with meeting the requirements proposed for these relays. Lockout relays operate rarely and are known for reliable service. For many such relays, the proposed maintenance would require clearance of entire bus sections or even multiple bus sections (such as for a bus differential lockout relay). In SCL's opinion, the reliability risks posed by such switching and outages to the Bulk Electric System outweigh the reliability benefits of including lockout relays in the scope of PRC-005-2. If the SDT deems it necessary to include electromechnical lockout relays within PRC-005-2, SCL recommends that a difference be made between the maintenance activities specified for monitored and unmonitored types. The draft Standard describes the requirements for "electromechanical lockout and/or tripping auxiliary devices" in Table 1-5 (p.19) and assigns a 6-year maximum maintenance interval, the same as for other unmonitored relays. Modern electromechanical lockout relays may be specified with a built-in self-monitoring trip-coil alarm. SCL believes the maintenance requirements for electromechanical lockout relays with such an alarm should be similar to those for other alarmed or monitored relays. As such we recommend that a new entry be added to Table 1-5 for monitored electromechanical

Organization	Yes or No	Question 3 Comment
		lockout relays, as follows: • Component Attributes: Electromechanical lockout and/or tripping auxiliary devices which are directly in a trip path from the protective relay to the interrupting device trip coil AND include built-in self-monitoring trip-coil alarm • Maximum Maintenance Interval: 12 calendar years • Maintenance Activities: Verify electrical operation of electromechanical trip and auxiliary devices. Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. Regarding confusion over language, section 4.2 section identifies five types of Facilities that the standard is applicable to, whereas Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). As such, it is not clear if PRC-005-2 applies to five Facilities or to certain Protection Systems. SCL believes the intent is to have a PSMP for all Protection Systems identified in "Part A, Section 4.2 - Facilities" and that the language of Requirement 1 may cause confusion or be misleading. We suggest changing the language of Requirement 1 from: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Facilities identified in Part A, Section 4.2.
Response: Thank you for your comments. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to the same comments on the proposed standard provided elsewhere in this report.		
Beaches Energy Services (1)	Non-binding Poll Comment	We believe that there is an unnecessary expansion of the scope of equipment covered by this standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The new PRC-005-2 includes these non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability. We agree wholeheartedly with the inclusion of non-relay components for BES Protection Systems. It is critical

Organization	Yes or No	Question 3 Comment
		that BES Protection Systems work and clear the fault (e.g., on > 100 kV Facilities). However, UFLS and UVLS are quite different. For an event requiring UFLS and UVLS operation, there are many, e.g., hundreds and possibly thousands of relays, that operate to shed load automatically and if a small percentage of those do not operate as expected, the impact is minimal. So, it is not important for BES reliability to include non-relay components of UFLS and UVLS in the PRC-005-2 standard. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. For instance, testing trip coils of distribution breakers will likely result in service interruption to customers on that distribution circuit in order to test the breaker or to perform break-before-make switching on the distribution system often required to manage maximum available fault current on the distribution system for worker safety, etc.. Hence, the standard would be sacrificing customer service quality for an infinitesimal increase in BES reliability. In addition, non-relay protection components operate much more frequently on distribution circuits than on Transmission Facilities due to more frequent failures due to trees, animals
Response: Thank you for your comments. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to the same comments on the proposed standard provided elsewhere in this report.		
City of Green Cove Springs (3)	Non-binding Poll Comment	GCS believes that there is an unnecessary expansion of the scope of equipment covered by this standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The new PRC-005-2 includes these non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability. GCS agrees wholeheartedly with the inclusion of non-relay components for BES Protection Systems. It is critical that BES Protection Systems work and clear the fault (e.g., on > 100 kV Facilities). However, UFLS and UVLS are quite different. For an event requiring UFLS and UVLS operation, there are many, e.g., hundreds and possibly thousands of relays, that operate to shed load automatically and if a small percentage of those do not operate as expected, the impact is minimal. So, it is not important for BES reliability to include non-relay components of UFLS and UVLS in the PRC-005-2 standard. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. For instance, testing trip coils of a distribution breakers will likely results in service interruption to customers on that distribution circuit in order to test the breaker or to perform break-

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>before-make switching on the distribution system often required to manage maximum available fault current on the distribution system for worker safety, etc.. Hence, the standard would be sacrificing customer service quality for an infinitesimal increase in BES reliability. In addition, non-relay protection components operate much more frequently on distribution circuits than on transmission Facilities due to more frequent failures due to trees, animals, lightning, traffic accidents, etc., and have much less of a need for testing since they are operationally tested.

As another comment, station service transformers are not BES Elements and should not be part of the Applicability - they are radial serving only load.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. These comments are not relative to the non-binding poll of the VRFs and VSLs for PRC-005. Please see our response to the same comments on the proposed standard provided elsewhere in this report.</td></tr>
<tr><td>ReliabilityFirst</td><td>Non-binding Poll Comment</td><td>ReliabilityFirst agrees with the VRFs but votes negative on the VSLs for the following reasons:

1. VSL for R1
a. Part 1.3 is not mentioned in the VSLs
b. The VSLs should start off with the phrase “The responsible entities PSMP…”
c. For the VSLs dealing with Part 1.2, the term “or a combination” should be added as one of the methods for maintenance.
d. The last VSL under the Severe category should reference Part 1.2
e. The VSLs for Part 1.1 should be gradated similar to Part 1.2 (e.g. what VSL does an entity fall under if they failed to address two component types included in the definition of ‘Protection System’?)
2. VSL for R2
a. To be consistent with Requirement 2, the VSLs should start off with the phrase “The responsible entity uses performance-based maintenance intervals in its PSMP, but…”
b. The first VSL under the “Lower” category is a duplicate of the VSL under the “High” category
c. The third VSL under the “Lower” category has language stating “or containing different manufacturers.” Neither R2 nor Attachment A mentions this language. This is a violation of the FERC Guideline 3: “Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement”
d. Recommend that the VSL regarding entities that “maintained a segment with less than X amount of components” should be a binary “Severe” VSL
3. VSL for R3
a. The VSLs should start off with the phrase “The responsible entity…”</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		b. R3 does not require an entity to "…complete scheduled program…" This is a violation of the FERC Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement" c. The "implement and follow its PSMP" language in R3 is not mentioned in the VSLs for R3. Recommend including this language in the VSLs for R3

Response: Thank you for your comments.

1.

a. Part 1.3 has been added to the R1 High VSL.

b. The R1 Lower, Medium, and Higher VSLs have been modified as you suggest.

c. The R1 Lower, Medium, and Severe VSLs have been modified as you suggest.

d. The R1 Severe VSL has been modified as you suggest

e. The R1 Moderate and High VSLs have been modified to add graduated VSLs for part 1.1.

2.

a. The R2 VSLs have been modified as you suggest.

b. Thank you for catching this. The High VSL has been modified from three years to four years.

c. This portion of the R2 Lower VSL has been removed, making the VSL for this portion of R2 binary (with only a Severe VSL).

d. The VSL for R2 has been modified as you suggest.

3.

a. The R3 VSLs have been modified as you suggest.

b. The R3 VSLs have been modified by replacing "complete" with "implement and follow" in consideration of your comment.

c. The R3 VSLs have been modified by replacing "complete" with "implement and follow" in consideration of your comment.

4. **The SDT has incorporated the FAQ document into the "Supplementary Reference" document and has provided the combined document as support for the Requirements within the standard. Do you have any specific suggestions for further improvements?**

Summary Consideration: The commenters were generally supportive of the combination of documents.

Several comments were offered, repeating previous questions regarding the enforceability of this document, and the SDT repeated previous responses explaining the status of this document as a supporting reference – reference documents have no enforceability.

A variety of suggestions were offered regarding additional information for the document, which largely resulted in modifications to the Supplementary Reference document. One specific suggestion of note (resulting in additional discussion within the document) requested a FAQ regarding "Calendar Year".

Several commenters posed questions regarding "grace periods" and "PSMPs established by entities that are more stringent than the requirements within the standard". No additional changes were made due to these questions, but the SDT further explained previous guidance on these issues within the responses. Entities are always allowed to implement practices that are more stringent than those identified in a standard.

Organization	Yes or No	Question 4 Comment
Manitoba Hydro		A red line was not provided making this document difficult to review. We suggest that a redline of this document be posted.
Response: Thank you for your comments. A red-line was not provided because of overall extensive changes, resulting from merging of the previous Supplementary Reference Document and FAQ; the entire document would have been red-line. The next posting will include a red-lined document, as well as the "clean" document.		
U.S. Bureau of Reclamation (5)	Ballot Comment - Affirmative	1. The reference material provides a significant insight into the intent of the proposed changes to the standard. In some cases an interpretation is provided which is not supported by the explicit interpretation of the standard text. The SDT is encouraged to either attach the reference material to the standard or add relevant sections to standard as Background. The Background section could reference the Supplemental Reference & FAQ. 2. The reference material provides more detail indicating that "Voltage & Current Sensing Device circuit input

Organization	Yes or No	Question 4 Comment
		connections to the protection system relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. . . . . . The values should be verified to be as expected, (phase value and phase relationships are both equally important to verify).” This interpretation is not consistent with the text of the standard and would suggest that it be incorporated into Table 1-3. 3. When protective equipment is replaced, the reference information indicates that the information associated with the original equipment must be retained to show compliance with the standard until the performance with the new equipment can be established. This is not stated in the Measurements and should be added if the expectation exists.
Response: Thank you for your comments. 1. This standard is not being developed in a “results-based” format. Attaching the extra document as you suggest would make the supporting information within the FAQ and Supplementary Reference part of the standard, and this would add extensive and unnecessary prescription to the standard. As you suggest the reference material is listed within the Standard (Section F – Supplemental Reference Document). The next revision will likely resemble your suggestion. 2. Details within the Supplemental Reference Document are provided as examples and should not be construed as limitations or additional requirements. The intent of the supplementary information is to spur insight into possible means of satisfying requirements and is not intended to promote a single technical method of accomplishing tasks. 3. M1 states “Each Transmission Owner, Generator Owner, and Distribution Provider shall have evidence that it has implemented the Protection System Maintenance Program and…” Documenting the implementation of the PSMP certainly requires evidence that maintenance was performed at the prescribed intervals and the data retention requirements state that evidence of the two most recent performances of each distinct maintenance activity be retained. Also, please see the NERC Compliance Process Bulletin #2011-001 (“Data Retention Requirements”) for similar guidance.		
Ameren Services (1)	Ballot Comment – Affirmative	1. Omit retention of maintenance records for replaced equipment. Supplement FAQ 12.1 on page 51 final sentence states that documentation for replaced equipment must be retained to prove the interval of its maintenance. We oppose this because: the replaced equipment is gone and has no impact on BES reliability; and such retention clutters the data base and could cause confusion. For example, it could result in saving lead acid battery load test data beyond the life of its replacement. Since BES Element protection is the objective, we suggest a compromise of keeping the evidences of last test for the removed equipment and using that with the equivalent function replacement equipment commissioning or in-service date to prove interval. 2. In Supplement examples on pp 22-23, replace “Instrumentation transformers” with “Verify that current and voltage signal values are provided to the protective relays” to be consistent with Table 1-3. 3. Remove “Reverse power relays” from the sample list of generator devices in Supplement p31 because reverse power relays are applied for mechanical protection of the prime mover, not electrical protection of the

Organization	Yes or No	Question 4 Comment
		generator. 4. Revise Supplement Figure 1 & 2 Legend p83 to align with Draft 4 (a) state “Protective relays designed to provide protection for BES Element(s)” (b) state “Current and voltage signals provided to the protective relays”. 5. Please add a Performance-Based maintenance example for control circuitry, and /or voltage and current sensing.
Response: Thank you for your comments. 1. This cited reference in the Supplementary Reference Document is present to maintain consistent evidence that maintenance was performed within prescribed intervals. Please see the NERC Compliance Process Bulletin #2011-001 (“Data Retention Requirements”) for similar guidance. 2. Thank you, the change has been made. 3. The commenter is correct that it is the prime mover that is protected by the Reverse Power relay; however the Standard considers relays (such as Reverse Power relays) that sense voltage and current are within the scope. Furthermore, Part 4.2.5.1 (Applicability) of the Standard includes Protection Systems for generator Facilities that are part of the BES including Protection Systems that act to trip the generator either directly or via generator lockout or auxiliary tripping relays. 4. The column marked Component of Protection System closely aligns with the definition of Protection System as approved by the NERC Board of Trustees and is included within the Standard itself. The next column (“Includes”) is more explanatory in nature and is intended to give insight on the SDT’s intent. 5. Thank you, the requested changes have been made. Additional Q&A (including one for control circuitry and one for voltage and current sensing devices) have been added to Section 9.2.		
National Grid (1)	Ballot Comment - Affirmative	National Grid suggests that FAQ be added: 1. Regarding Table 2 in the standard, Does a fail-safe “form b” contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring? 2. Please add a clarification as part of the FAQ document that defines whether the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, must be tested per Table 1.5.
Response: Thank you for your comments. 1. Thank you, the change has been made. An additional Q&A has been added to Section 15.6.1. 2. Thank you, the change has been made. An additional Q&A has been added to Section 15.3.1.		

Organization	Yes or No	Question 4 Comment
New York Power Authority (1)	Ballot Comment - Affirmative	Comments: We suggest that FAQ be added: 1. Regarding Table 2 in the standard, Does a fail-safe “form b” contact that is alarmed to a 24/7 operation center classify as an alarm path with monitoring? 2. Please add a clarification as part of the FAQ document that defines whether the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, must be tested per Table 1.5.
Response: Thank you for your comments. 1. Thank you, the change has been made. An additional Q&A has been added to Section 15.6.1. 2. Thank you, the change has been made. An additional Q&A has been added to Section 15.3.1.		
Muscatine Power & Water (3)	Ballot Comment - Affirmative	In the “Supplemental Reference and FAQ” document on page 65 there is one area of concern. In paragraph 4 “…the type of test equipment used to establish the baseline must be used for any future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer’s equipment.” While MP&W understands the importance of creating a valid baseline, it is disingenuous to expect the test equipment to be the same as the manufacturer’s test equipment. For that matter, it would be highly unlikely the same test equipment would be used over the life of the battery. The expected life of a battery may be in excess of 15 years in most cases and it would not be probable to expect that the type of test equipment is not going to change during this period. MP&W suggests changing the wording to read that CONSISTENT test equipment should be used to provide consistent/comparable results.
Response: Thank you for your comments, the change has been made. The statements concerning types of equipment have been changed per your suggestion to reflect consistent test data as opposed to exactly the same piece of test equipment.		
Florida Municipal Power Agency (4) (5) (6) Florida Municipal Power Pool (6)	Ballot Comment - Negative	1. Examples #1, #2 and #3 in Section 7.1 of the Supplementary Reference all indicate that it is a requirement to “verify all paths of control and trip circuits” every 12 years. As stated, there would be circuits included in the testing requirement that the SDT did not mean to include in the scope of the Standard (e.g., SCADA closing circuit.) The statements in the illustrative examples should be changed to “verify all paths in the control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices” to be in line with the definition of a Protection System. 2. Section 15.5 of the Supplementary Reference Document states: “It was the intent of this Standard to require that a test be made of any communications-assisted trip scheme regardless of the vintage of the technology. The essential element is that the tripping (or blocking) occurs locally when the remote action

Organization	Yes or No	Question 4 Comment
		has been asserted; or that the tripping (or blocking) occurs remotely when the local action is asserted". The SDT should reword this statement recognizing that tests performed on communication systems may not be performed at the same time an entity chooses to perform trip tests on the associated breaker(s). The notion of "overlapping" can be applied, for instance, by taking an outage on one relay set in a fully redundant system, initiating a trip signal from the remote end and observing the trip signal locally. All remaining portions in the local communication-assisted trip paths can then be tested when the local line panel is taken out of service for maintenance.
Response: Thank you for your comments. 1. Thank you, the change has been made. 2. Thank you, the change has been made.		
ITC	No	We agree with the combination of the two. One document with the FAQ's grouped with the supplemental topics makes it easier to review the whole topic.
Response: Thank you for your comments.		
Central Lincoln	No	The first FAQ under 2.3.1 is incorrect, referencing a FERC informational filing. Included in the filing was a WECC test that was never approved by the WECC board and is not being used. Using this document as suggested will get WECC entities into trouble.
Response: Thank you for your comments. There are presently regional differences allowed that may cease to exist once the BES is redefined. The SDT for the BES Definition (Project 2010-17) is charged with developing a continent-wide BES definition; however, this FERC informational filing is on the public record, and was part of the basis for FERC Order 743.		
Tampa Electric Company	No	Tampa Electric requests further differentiation between BES protection elements and UFLS equipment.
Response: Thank you for your comments. UFLS equipment is presently covered under PRC-008. PRC-005-2 will cover all Protection Systems components including components used for UFLS. The Standard addresses UFLS and UVLS to the degree that they are installed per NERC Standards, even though entities may choose to install them on distribution systems. This is an intentional difference between UFLS/UVLS and the remainder of the Protection Systems addressed within the Standard, because of the distributed nature of UFLS/UVLS and because these devices are usually tripping non-BES system elements.		
Electric Market Policy	No	
Santee Cooper	No	

Organization	Yes or No	Question 4 Comment
SPP reliability standard development Team	No	
Tennessee Valley Authority	No	
Imperial Irrigation District	No	
MRO's NERC Standards Review Subcommittee	No	
The Detroit Edison Company	No	
NextEra Energy	No	
Western Electricity Coordinating Council	No	
Ingleside Cogeneration LP	No	
Farmington Electric Utility System	No	
Illinois Municipal Electric Agency	No	
Shermco Industries	No	
Dominion Virginia Power	No	
American Electric Power	No	
CPS Energy	No	
Indeck Energy Services	No	
MidAmerican Energy Company	No	

Organization	Yes or No	Question 4 Comment
NIPSCO	Yes	We used the FAQ Supplemental Reference while reviewing this draft standard and found it useful.
Response: Thank you for your comments.		
FirstEnergy	Yes	1. We do not agree with the following wording on page 37 of the reference document: (1) “If your PSMP (plan) requires more activities then you must perform and document to this higher standard.” and (2) “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.” 2. We continue to believe that the auditor is required to audit to the standard. If the standard requires maintenance intervals every 6 years, this is what the auditor should verify. This was also verified in the recent NERC Workshop at which it was confirmed that “auditors must audit to the standard”. To this end, we also suggest changes to Requirement R3 as explained in our comments in Question 5.
Response: Thank you for your comments. 1. The SDT respectfully disagrees with the commenter. R1 of the Standard states that “… shall establish a Protection System Maintenance Program (PSMP)…, and R3 states that “… shall implement and follow its (PSMP)…” Therefore, if an entity has a more stringent PSMP then they must follow their own PSMP. An example of this might be a case that has an entity with Performance Based Maintenance; this entity could find time intervals between maintenance activities that are more frequent than are laid out in the Tables. This entity must follow their PSMP. Another example might be an entity that requires CT Saturation tests every 10 years; this is a more stringent requirement than is contained within the minimum maintenance activities of the Standard. Neither the SDT nor any auditor has any idea why an entity may require more stringent requirements of themselves than the Standard requirements. Even under the present PRC-005-1 an auditor audits to the entity’s PSMP; a case in point is if an entity PSMP requires relay testing with simulated fault values of voltage and current every year then they are audited to that requirement (even though PRC-005-1 specifically does not require any particular relay testing and certainly has no time intervals stated). Please note that FERC Order 693 directs NERC to establish maximum allowable intervals not minimum intervals, and the entity’s program must, at a minimum, conform to those intervals. 2. The SDT has set no requirements that an entity have a more stringent PSMP than the minimum requirements set out in the Standard, only that any PSMP meet the minimums laid out within the Standard. But, should an entity have a PSMP that is more stringent then, according to R3, they must maintain to their own more stringent PSMP.		
BGE	Yes	1. The supplementary reference on page 30, under the question beginning “Our maintenance plan requires” 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, under the question, “How do I achieve a grace period without being out of compliance” provides an example of scheduling maintenance at four year intervals in order to manage scheduling complexities and assure completion in less in less than the maximum time of six calendar years. This is

Organization	Yes or No	Question 4 Comment
		conflicting advice. The FAQ /supplementary reference should be revised so that it does imply that an entity is out-of-compliance by performing maintenance more frequently than required. Avoiding compliance risk is one reason to do this, but there are other valid motives not directly related to reliable protection system performance. 2. Testing of PT's and CT's (12 year max) is non invasive and convenient to schedule at the same time as relays (6 year max) just to keep procedures consistent and reduce program administration. Testing of ties to other TOs or GOs may have to be scheduled more frequently than preferred in order to synchronize schedules.
Response: Thank you for your comments. 1. There is no conflict, the first commenter-cited PSMP example has language that has no grace-period built in, and the second commenter-cited PSMP example has language with a built-in grace period. Both cited examples are measurable to a time limit between testing activities. 2. Your observations are correct; an entity may choose to perform activities more often than is specified in the Standard. For that matter, an entity may choose to perform activities more often than their own PSMP; the entity simply cannot exceed their own PSMP intervals which in turn cannot exceed the intervals in the Standard.		
Pepco Holdings Inc	Yes	The Supplementary Reference and FAQ should be an attachment to the standard (Appendix A) and not just referenced. If not attached it will not be readily accessible to those that will be using the standard.
Response: Thank you for your comments. The Supplementary Reference and FAQ is referenced in Section F of the standard (which was on Page 9 of the clean version of the recent posting), in accordance with the Standards Development Process, and will be posted with the standard as "Reference Materials".		
GDS Associates	Yes	The standard should include a footnote indicating this document as reference
Response: Thank you for your comments. This document is addressed within the Standard as a reference document by listing it in Section F (which was on Page 9 of the clean version of the recent posting), in accordance with the Standards Development Process.		
ExxonMobil Research and Engineering	Yes	The SDT should provide notes that reference the sources used for developing the maximum maintenance intervals utilized in the time-based program, and provide a technical explanation as to why they have not provided a tolerance band for use with the time-based program. What is the increase in risk owned by an entity when a protective device is tested at the 6 year and 30 day mark instead of the 6 year mark?
Response: Thank you for your comments. The SDT was tasked to create a standard with maximum time intervals between maintenance activities. Thus the task, in and of itself, sets the limit as absolute. Where the intervals were set at six years (or any interval for that matter), there was no assessment of risk beyond the time interval chosen as the absolute. The question always would arise as "Why not an additional thirty days after that?" The reference material cites methodology		

Organization	Yes or No	Question 4 Comment
to determine initial time intervals. The SDT took further care to try to align the initial maintenance intervals with common maintenance schedules like plant outages and other published guidelines. Please note that the Tables refer to "Calendar Year" for the intervals referenced in the comment; the noted concern would only be relevant if the entity actually completes the activity at the very end of the calendar year.		
US Army Corps of Engineers	Yes	1. The reference material provides a significant insight into the intent of the proposed changes to the standard. In some cases an interpretation is provided which is not supported by the explicit interpretation of the standard text. The SDT is encouraged to either attach the reference material to the standard or add relevant sections to standard as Background. The Background section could reference the Supplemental Reference & FAQ. 2. The reference material provides more detail indicating that "Voltage & Current Sensing Device circuit input connections to the protection system relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. . . . . . The values should be verified to be as expected, (phase value and phase relationships are both equally important to verify)." This interpretation is not consistent with the text of the standard and would suggest that it be incorporated into Table 1-3.
Response: Thank you for your comments. 1. This standard is not being developed in a "results-based" format. As you suggest the reference material is listed within the Standard (Section F – Supplemental Reference Document). The next revision will likely resemble your suggestion. 2. Details within the Supplemental Reference Document are provided as examples and should not be construed as limitations or additional requirements. The intent of the supplementary information is to spur insight into possible means of satisfying requirements and is not intended to promote a single technical method of accomplishing tasks.		
Luminant	Yes	The document was valuable in understanding PRC-005-2 by providing clarification using practical protective relay system examples. Below are two comments for further improvement. 1. It would be beneficial if the document could provide additional information for relaying in the high-voltage switchyard (transmission owned) - power plant (generation owned) interface. While Figures 1 and 2 are typical generation and transmission relay diagrams, it would be helpful if protective relays typically used in the interface also be included. For example, a transmission bus differential would remove a generator from service by tripping the generator lockout. 2. Figures 1 and 2 refer to a "Figure 1 and 2 Legend" table which provides additional information on qualifications for relay components. Should a footnote be used to point toward Reference 1 (Protective

Organization	Yes or No	Question 4 Comment
		System Maintenance: A Technical Reference) located in Section 16?
Response: Thank you for your comments. 1. There are so many variations possible that it is impractical to try to capture all configurations on a single picture or in a single document. However, for the cited example - a transmission bus Protection System would be included. All five of the Protection System component types would fall within the Standard including the trip paths and the electrical test requirements of the generator lockout device. 2. Thank you, a link has been provided to the references.		
MISO Standards Collaborators	Yes	The additional documentation seems to be quite large, and the additional content seems to go far beyond what is necessary for the PRC-005-2 standard. We recommend the SDT lessen the amount of content provided in the “Supplementary Reference” document.
Response: Thank you for your comments. Details within the Supplemental Reference Document are provided as examples and should not be construed as limitations or additional requirements. The intent of the supplementary information is to spur insight into possible means of satisfying requirements and is not intended to promote a single technical method of accomplishing tasks.		
Northeast Power Coordinating Council	Yes	Suggest that to FAQ be added: 1. Regarding Table 2 in the standard, does a fail-safe “form” contact that is alarmed to a 24/7 operation center qualify as an alarm path with monitoring? 2. Add a clarification as part of the FAQ document that defines whether the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, must be tested as per Table 1.5.
Response: Thank you for your comments. 1. Thank you, the change has been made. An additional Q&A has been added to Section 15.6.1. 2. Thank you, the change has been made. An additional Q&A has been added to Section 15.3.1.		
Georgia Transmission Corporation	Yes	See comments for item 1 and continue clarification where we could include high side or distributed interrupting devices, exchange nomenclature removing distribution breaker and adding distributed interrupting device or non-BES equipment.
Response: Thank you for your comments. Circuit interrupting devices that only participate in a UFLS or UVLS scheme are excluded from the tripping requirement, but not from the circuit test requirements. The “non-BES equipment interruption device” phrase has been inserted as suggested.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td>PNGC Comment Group</td><td>Yes</td><td>Section 9.2 (copied below) indicates that small entities can utilize Performance-Based PSMP if they aggregate with other entities. Does this section indicate that only a parent entity with individually owned components can aggregate, or can independent entities under a G&T aggregate? In other words, individual DP/LSE/TOs with different audits. Can they aggregate under a common PSMP for performance based maintenance?

9.2 Frequently Asked Questions: I’m a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity? Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for performance-based maintenance must be met for the overall aggregated program on an ongoing basis. The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

Two entities in such a shared program must have populations of components that can be aggregated and the PSMP for those components are the same between the two entities. Thus the combined entities can show total populations, total numbers of components tested and total failures found. The combined entities would thus be forced to follow the same intervals, test procedures and statistical analysis. There would have to be cooperation between entities but in the end the outcome would be the same as if the PBM process were applied to a single entity. There is no inherent advantage or disadvantage to multiple entities cooperating in such a manner. The SDT intends that small entities with small populations of equipment have the same access to PBM as the larger entities.</td></tr>
<tr><td>FHEC</td><td>Yes</td><td>It is unclear what compliance obligations may be created or clarified with the FAQ. It is a good explanatory document and a helpful reference, but the Standard should speak for itself as it relates to what it takes to achieve compliance.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The Standard is the only “mandatory and enforceable” document. Details within the Supplemental Reference Document are provided as examples and should not be construed as limitations or additional requirements. The SDT intends that it be posted as a Reference Document, accompanying the standard.   As established in SDT Guidelines, the Standard is to be a terse statement of requirements, etc, and is not to include explanatory information like that included in the Supplementary Reference Document. The Supplementary Reference FAQ will be revised in the course of the revision process of the standard.</td></tr>
<tr><td>Western Area Power</td><td>Yes</td><td>Can the SDT add a better definition or clarification of ”Calendar Year” as it pertains to PRC-005-2 and provide</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
Administration		examples or parameters of Compliance with the Standard requirements and tables? Calendar Year is explained in various details within Pages 35-Pages 37 of the Supplementary Reference and FAQ. This important attribute of a TBM or TBM/CBM combination program is not easily found in the Table of Contents or section sub-headings.
Response: Thank you for your comments. Per your suggestion, a “What is a Calendar Year?” Q&A has been added to the front end of Section 7.1.		
Duke Energy	Yes	Along the lines of what we have suggested in our comment to Question #1 above, we believe it would make compliance more certain if selected language from the Supplementary reference could be incorporated into the standard, either directly in requirements, or in footnotes.
Response: Thank you for your comments. The addition that you suggest is properly considered application guidance; the SDT has been advised that this information is not to be included within the standard, and that it is appropriately included in separate reference materials.		
Ameren	Yes	1. Comments: Supplement FAQ 12.1 on page 51 final sentence states that documentation for replaced equipment must be retained to prove the interval of its maintenance. We oppose this because: the replaced equipment is gone and has no impact on BES reliability; and such retention clutters the data base and could cause confusion. For example, it could result in saving lead acid battery load test data beyond the life of its replacement. Since BES Element protection is the objective, we suggest a compromise of keeping the evidences of last test for the removed equipment and using that with the equivalent function replacement equipment commissioning or in-service date to prove interval. 2. Clarify p17 Table 1-4(e) interval meaning. We think this means we need to verify the Station dc supply voltage on 12 calendar year interval if unmonitored, or no periodic maintenance if monitored as stated. 3. In Supplement examples on pp 22-23, replace “Instrumentation transformers” with “Verify that current and voltage signal values are provided to the protective relays” to be consistent with Table 1-3. 4. Remove “Reverse power relays” from the sample list of generator devices in Supplement p31 because reverse power relays are applied for mechanical protection of the prime mover, not electrical protection of the generator. 5. Revise Supplement Figure 1 & 2 Legend p83 to align with Draft 4 (a) state “Protective relays designed to provide protection for BES Element(s)”. (b) state “Current and voltage signals provided to the protective relays” 6. Please add a Performance-Based maintenance example for control circuitry, and /or voltage and current sensing.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. 1. This cited reference in the proposed Standard is present to maintain consistent evidence that maintenance was performed within prescribed intervals. 2. The SDT agrees. 3. Thank you, the change has been made 4. The commenter is correct that it is the prime mover that is protected by the Reverse Power relay, however the Standard considers relays (such as Reverse Power relays) that sense voltage and current as within the scope. Furthermore, Part 4.2.5.1 of the Standard states that Protection Systems for generator Facilities that are part of the BES including Protection Systems that act to trip the generator either directly or via generator lockout or auxiliary tripping relays 5. The column marked Component of Protection System closely aligns with the definition of Protection System as approved by the NERC Board of Trustees and is included within the Standard itself. The next column ("Includes") is more explanatory in nature and is intended to give insight on the SDT intent 6. Thank you, the changes have been made. Additional Q&A have been added to Section 9.2.		
Xcel Energy	Yes	1) On page 65, paragraph 4, of the "Supplemental reference and FAQ" document, it states:"the type of test equipment used to establish the baseline must be used for any future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer's equipment." While we understand the importance of creating a baseline, it is not feasible to expect the test equipment be the same as the manufacturer's test equipment or even the same test equipment over the life of the battery. The expected life of a battery may be in excess of 20 years and it is not feasible to expect that the type of test equipment will not change during this period.2) A FAQ to clarify in scope protection systems for variable energy resource facilities (wind, solar, etc) would be very helpful. 2) Does paragraph 4.2.5.3 "Facilities" imply that the only protection system associated with a wind farm that is considered in scope for PRC-005-2 is that for the aggregating transformer? If other protection systems associated with a wind farm are in scope, please clarify which systems would be in scope for PRC-005-2. For example, a typical wind farm in our system might have 30-33, 1.5MVA windmills connected to one 34.5 KV collecting feeder circuit for a total of roughly 50 MVA per collecting feeder. 4 of these 50 MVA collecting feeders are tied via circuit breakers to a low side 34.5 KV bus which in turn is connected via a low side breaker to aggregating step up transformer which then connects to the BES transmission system. Obviously per paragraph 4.2.5.3, the protection system for the aggregating step up transformer is in scope. What about the protection system for the transformer low side 34.5 KV breaker - serving 200 MVA of aggregate generation? What about the protection system of each individual 34.5 KV aggregating

Organization	Yes or No	Question 4 Comment
		feeder - 50 MVA of aggregate generation? What about the"protection system" for each individual 1.5 MVA windmill? An FAQ on this topic would be very helpful.
Response: Thank you for your comments. 1. Thank you for your suggestion; the paragraph cited has been changed. 2. Clause 4.2.5.3 states specifically that the Protection Systems on the aggregating transformer are included. The SDT has not specifically included other equipment, but, depending on what, specifically, is defined to be BES for these facilities, either within current Regional definitions or within the emerging NERC definition, other equipment may be drawn in.		
Alliant Energy	Yes	

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

Summary Consideration: 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 comments were offered, suggesting that PRC-005-2 needs to be consistent with the interpretation in Project 2009-17, now implemented as PRC-005-1a, and the SDT modified Applicability 4.2.1 for better consistency with the interpretation 4.2.1 (Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc).

Many comments were offered objecting to the 3-calendar-month intervals for station dc supply and communications systems, and suggesting that a 3-calendar-month interval requires entities to schedule these activities for 2-calendar-months in order to assure compliance. The SDT did not modify the standard in response to these comments, and responded that the intervals were appropriate, and that entities should be able to assure compliance on a 3-calendar-month schedule by using program oversight. The "Supplementary Reference and FAQ" document was augmented with additional explanatory text.

Several comments were offered questioning various aspects of Applicability 4.2.5.4 (generation auxiliary transformers). No changes were made in response to these comments, and responses were offered illustrating why these transformers are included.

Many (essentially identical) comments were offered, questioning the propriety of including distribution system Protection Systems, almost all related to UFLS/UVLS. The SDT explained that these Protection Systems are appropriate to be included for consistency with legacy standards PRC-008, PRC-011, and PRC-017, and noted that their inclusion is consistent with Section 202 of the NERC Rules of Procedure.

Several comments were offered, objecting to the 6-calendar-year interval for lockout and auxiliary relays. The SDT declined to adopt the requested changes, and noted that these "electromechanical" devices with "moving parts" share failure mechanisms with electromechanical protective relays and that the intervals should be identical.

Several comments were offered regarding Maintenance Correctable Issues, and resulted in modifying this definition to be "…such that the deficiency cannot be corrected during the performance of the maintenance activity …"

Assorted additional comments were offered by individual commenters (most of them similar to comments on previous postings), which resulted in responses similar to those offered during previous posting periods.

Organization	Yes or No	Question 5 Comment
Consolidated Edison Co. of New York (1) (3) (5)	Ballot Comment - Affirmative	We recommend that the drafting team recognize that a “fail safe” or “self-reporting” alarm design serves as an acceptable alternative to periodic testing. This “fail safe” or “self-reporting” alarm design is equivalent to continuous testing the alarm. When the alarm circuit fails the alarm is set to “alarm on” and automatically notifies the control center, initiating a corrective action.
Response: Thank you for your comments. The application discussed seems to the SDT to be an effective method of “monitoring the monitoring circuit”. (See Table 2, last row with heading “Alarm Path with monitoring.”)		
Ameren Services (1)	Ballot Comment - Affirmative	(1) Need some tolerance – require 99% of components to meet R3. Measure M3 on page 5 should apply to 99% of the components. “Each … shall have evidence that it has implemented the Protection System Maintenance Program for 99% 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 in that valuable resources will be distracted from other duties. (2) Define BES perimeter in accordance with Project 2009-17 Interpretation. Facilities Section 4.2.1 “or designed to provide protection for the BES” needs to be clarified so that it incorporates the latest Project 2009-17 interpretation. The industry has deliberated and reached a conclusion that provides a meaningful and appropriate border for the transmission Protection System; this needs to be acknowledged in PRC-005-2 and carried forward. The BOT adopted this 2/17/2011. (3) Battery inspection every 4 months is sufficient. IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months due to storms and outages must set a target interval of two months thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, we also suggest that all intervals expressed as 3 calendar months be changed to 4 calendar months.
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. 2. The referenced interpretation relates to a quasi-definition of “transmission Protection System”, and in the context of the approved PRC-004-1 and PRC-005-1, presents a consistent context for this term. However, the interpretation was constrained to not introducing any requirements or applicability not already included within the approved standards. PRC-005-2 does not use this term, and expands upon the applicability in the interpretation to address what seems to the SDT to be an appropriate applicability for PRC-005-2. The applicability of the interpretation to PRC-004-1 is not affected by PRC-005-2. 3. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes		

Organization	Yes or No	Question 5 Comment
that an entity may schedule activities for a 3-calendar-month interval without a “grace period” if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month”. Basically every “3 Calendar Months” means to add 3 months from the last time the activity was performed.		
Xcel Energy		1) Regarding “Facilities” paragraph 4.2.5, we are in agreement with the elimination from scope of system connected station service transformers for those plants that are normally fed from a generator connected station service transformers. However, in the cases where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team’s intent to exclude the protection systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating facility? If the end result of the trip of the primary station service transformer is a trip of a BES generating facility, it would be more consistent to include the protection system for that transformer as in scope - whether it be connected to the system or to the generator. 2) 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 hope that the SDT will consider these changes.
Response: Thank you for your comments. 1. The SDT does not intend that the system-connected station auxiliary transformers be included in the Applicability. The 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. 2. The SDT believes that electromechanical devices share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-Based maintenance is an option to increase the intervals if the performance of these devices supports those intervals.		
Northeast Power Coordinating Council, Inc. (10)	Ballot Comment -	A concern exists that an entity with a very strict PSMP with intervals that are much shorter than neighboring entities or the standard will rewrite their PSMP and loosen their requirements to allow postponed maintenance

Organization	Yes or No	Question 5 Comment
	Affirmative	up the maximum specified in the standard. This standard, as written penalizes non-adherence to more stringent and better PSMPs and may inadvertently driving entities to the least common denominator. I am hopeful that Phase 2 will address this issue.
Response: Thank you for your comments. The Standard is defining maximum allowable intervals and minimum acceptable activities for a PSMP. Entities are empowered to develop PSMPs that exceed these requirements if they determine such a PSMP to be necessary.		
GDS Associates		Requirement R1 1. Suggest changing the language in R1.2 to read “Identify which maintenance method such as the time-based, performance-based (detailed in PRC-005 Attachment A), or a combination of the two would be appropriate to be used for each type of Protection System component. Based upon their own constructive type, all batteries associated with the station DC supply shall be included in a time-based maintenance program consistent with Table 1-4(a) through Table 1-4(f)” 2. Suggest changing the language for the first paragraph in R1.3 to read “Establish the occurrences associated with the time-based maintenance programs up to but no less than the time intervals specified in Table 1-1 through Table 1-5, and Table 2. Consequently, include all applicable monitoring attributes and related maintenance activities characteristic to each type of Protection System component specified in Table 1-1 through Table 1-5, and Table 2” 3. Suggest adding a sub-requirement such as R1.5 to read “Include documentation of maintenance, testing interval and their basis and a summary of testing procedures” Requirement R3 4. The redline version of the standard is misleading. Requirement R3 is crossed out and then replacing requirement R7 which is also crossed out. 5. The wording “initiates resolution of any identified maintenance correctable issues” it is vague. What a responsible entity should do to become compliant with this requirement? We also believe that is not sufficient to just “initiate resolution”; the standard should call for corrective actions to be performed within the maintenance time interval. 6. The “identified maintenance correctable issues” may not be a proper choice. The name of the new term suggests that is about issues that can be corrected during maintenance, while the definition from the clean version explains otherwise?

Organization	Yes or No	Question 5 Comment
		Additional requirement 7. Suggest adding a requirement to read "The Transmission Owner, Generator Owner, and Distribution Provider shall provide documentation of its PSMP and implementation to the appropriate Regional Reliability Organizations on request (within 45 calendar days)." 8. Add measure for the evidence on documenting the PSMP from the additional requirement General comments and notes 9. If you own electro-mechanical relays and microprocessor based relays is there a need to keep two different logs for these? 10. On table 1-4 the generator CTs should be tested earlier than the suggested 12 years due to exposure of continuous mechanical stress 11. Clarify table 1-5 to address verification tests on different circuits. Suggest that the Table 1-5 to read "Complete a terminal test of unmonitored circuitry" instead of the "Unmonitored control circuitry associated with protective functions" 12. In what instances (what extent) would the standard allow using the real time breaker operation to be considered maintenance as applicable to different types of relays involved in the real time event? This is briefly emphasized under TBM at paragraph 5.1 from the supplementary reference document?

Response: Thank you for your comments.

1. It is not enough for an entity to determine if time-based, performance-based, or a combination of the two would be "appropriate"; the entity must specify which method is being used, so that it is clear to both the entity and an auditor if R2 and Attachment A apply.

2. The SDT has considered your comment and has determined that the text currently within the requirement is appropriate.

3. The requirement that you suggest is identical to one of the most troublesome requirements from the approved PRC-005-1. By providing Tables 1-1 through 1-5, as well as Table 2, the SDT is establishing maximum allowable intervals as well as minimum required activities, and thus replacing this PRC-005-1 requirement with a more prescriptive one. If an entity chooses to extend the intervals and alter the activities by using monitoring, or to apply performance-based maintenance per R2 and Attachment A, the additional requirements related to those choices effectively establish a requirement such as you suggest.

4. The red-lining tools in Microsoft Word can sometimes be misleading, but the red-line is provided in an effort to illustrate the changes made to the document. We recommend that the entity use the "clean" version in order to see the final resulting text.

5. The SDT has considered that, while some maintenance correctable issues may be completed very quickly, others may take an extended period (perhaps even several years) to complete effectively, during which time the degraded system must be reported and reflected within the operation of the BES in accordance with

Organization	Yes or No	Question 5 Comment
other standards. The SDT is concerned that the entity will not be able to record the maintenance activity as "complete" during the scheduled interval for these more extended activities to "correct the maintenance correctable issue"; therefore, the SDT has opted to require only that the entity initiate correction of maintenance correctable issues within PRC-005-2 and rely on the operating focus on the degraded system to ensure that they are completed. The associated measure provides examples of relevant documentation. The definition of maintenance correctable issue has been revised to be clearer. 6. The phrase from the entire sentence states "initiate resolution of any identified maintenance correctable issues". This is to ensure follow-up for items which cannot be corrected during maintenance. The definition of maintenance correctable issue has been revised to be clearer. 7. No direct BES reliability purpose is supported by "on request documentation of a program"; this has value only for monitoring compliance. Additionally, Compliance Enforcement Authorities are empowered by the NERC Rules of Procedure to request information demonstrating compliance at any time. 8. No additional measure is necessary, as the suggested requirement is unnecessary. 9. The SDT is not specifying how the maintenance records are maintained relative to the Standard. It is up to the entity to determine how to best document the detailed implementation of their program. 10. Instrument transformers are addressed in Table 1-3, not Table 1-4. Entities are allowed to maintain components more frequently than required within the Standard if they feel it necessary. 11. The SDT does not believe that the suggested text adds clarity to the standard. Please see Section 15.3 of the Supplementary Reference Document for additional discussion. 12. The SDT suggests that observed in-service performance may be usable for any activities that are clearly verified by the in-service performance.		
Liberty Electric Power LLC		Apologies to the drafting team for submitting this with the ballot, repeated here to insure the comments are captured and addressed. While the SDT has done a very good job at responding to the most objectionable parts of the previous version, there are still a number of issues which makes the standard problematic. 1. The standard introduces the term "initiate resolution". This is an interpretable term, and has the potential for an auditor and an entity to disagree on an action. Would issuing a work order be considered "initiating resolution"? What if the WO had a completion date many years into the future? I would suggest adding the term to the list of definitions which will remain with the standard, and defining it as "performing any task associated with conducting maintenance activities, including but not limited to issuing purchase orders, soliciting bids, scheduling tasks, issuing work requests, and performing studies". 2. Some clarity is needed to differentiate system connected and generator connected station service transformers. A statement that a station service transformer connected radially to the generator bus is considered a system connected transformer if the transformer cannot be used for service unless connected to the BES. 3. The "bookends" issue, brought up in the prior round of comments, still exists. Although the SDT rightly notes a CAN has been issued regarding bookends, the CAN covers the documentation for system

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>components that entities were required to self-certify to on June 18, 2007. PRC-005-2 adds additional components to the protection system scheme which were not part of that certification, and has the potential to put entities into violation space due to a lack of records for those components. The SDT should add to M3 a statement that entities may demonstrate compliance with the standard by demonstrating that required activities took place twice within the maximum maintenance interval -starting from the effective date of the standard - for all components not listed in PRC-005-1.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

1. The SDT believes that issuing a work order would satisfy this requirement. M3 presents several examples of relevant evidence. The SDT has considered that, while some maintenance correctable issues may be completed very quickly, others may take an extended period (perhaps even several years) to complete effectively, during which time the degraded system must be reported and reflected within the operation of the BES in accordance with other standards. The SDT is concerned that the entity will not be able to record the maintenance activity as “complete” during the scheduled interval for these more extended activities to “correct the maintenance correctable issue”; therefore, the SDT has opted to require only that the entity initiate correction of maintenance correctable issues and rely on the operating focus on the degraded system to ensure that they are completed. The definition of maintenance correctable issue has been revised to be clearer.

2. The 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. System connected station service transformers were removed from the Applicability in a previous draft.

3. The Implementation Plan specifies that entities may implement PRC-005-2 incrementally throughout the intervals specified, and that they shall follow their existing program for components not yet implemented. The SDT believes that the “bookends” issue to which you refer is therefore addressed. Also, please see Compliance Process Bulletin 2011-001 for a discussion about data retention.</td></tr>
<tr><td>Central Lincoln</td><td></td><td>As we stated two ballots ago, we continue to believe that IEEE battery standard quarterly maintenance was never intended to be performed at a maximum interval of three months. Instead, three months is a target value that might be extended due to emergency. We continue to support a maximum interval of four months for these activities.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a “grace period” if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month”. Basically every “3 Calendar Months” means to add 3 months from the last time the activity was performed.</td></tr>
<tr><td>Tampa Electric Company</td><td></td><td>1. As written PRC-005-2 would have a very significant impact on Tampa Electric Company with very little reliability benefit. For the testing of the DC control circuits Tampa Electric would need to remove from</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		service each BES element (circuit, bus, transformer, breaker) and perform an R&C checkout somewhat equivalent to what Tampa Electric does for new construction. That process would have to be repeated no less often than every six years. The testing of DC control circuits to the level described / required in the proposed standard in an energized station is a very risky proposition. Even though an element can be taken out of service for testing, the DC control circuits are often interconnected for functions such as breaker failure, bus and transformer lockouts etc. It is very easy to accidentally trip other in service equipment while doing this testing. Another concern is getting outages on equipment to perform the proposed testing. 2. Tampa Electric believes that there is an unnecessary expansion of the scope of equipment covered by the proposed PRC-005-2 standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The proposed PRC-005-2 includes the non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, the non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the proposed standard with negligible benefit to BES reliability. 3. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. In addition, non-relay protection components operate much more frequently on distribution circuits than on transmission Facilities due to more frequent failures due to trees, animals, lightning, traffic accidents, etc., and have much less of a need for testing since they are operationally tested. 4. As another comment, station service transformers are not BES Elements and should not be part of the Applicability - they are radial serving only load. 5. Tampa Electric's Energy Supply Department has the following comment / question regarding Data Retention: For Requirement R3 R2 and Requirement R4R3, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or all performances of each distinct maintenance activity for the Protection System component since or to the previous scheduled audit date, whichever is longer. If all of the data which the proposed PRC-005-2 standard requires to be collected is not be available or kept for the prescribed period of time, how does a registered entity comply with the required data retention?
Response: Thank you for your comments. 1. Entities must employ processes and training on how to best manage risk . Not performing DC control circuit verification of protection functions is a risk to the		

Organization	Yes or No	Question 5 Comment
reliability of the BES. 2. Section 202 of the NERC Rules of Procedure define “Reliability standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition. The SDT notes that several Table entries for components that are used only for UFLS or UVLS involve fewer activities and/or longer intervals than for other similar components for generic Protection Systems. 3. The requirements related to UFLS and UVLS, which are commonly applied on non-BES equipment, are less involved than those for other Protection System equipment in recognition of the observations by the commenter. 4. The 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. System connected station service transformers were removed from the Applicability in a previous draft. 5. The stated data retention period is consistent with what auditors are expecting (per the SDT’s experience), and is also consistent with Compliance Process Bulletins 2011-001 and 2009-05. The entity is urged to assure that data is retained as specified within the Standard.		
American Transmission Company, LLC		1. Change the text of Standard PRC-005-2 - Protection System Maintenance Table 1-5 on page 19, Row 1, Column 3 to: ”Verify that a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.” Or alternately, ”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). 2. 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

Organization	Yes or No	Question 5 Comment
		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.ATC recognizes the substantial efforts and improvements to PRC-005-2 that have been made and appreciate the dedicated work of the SDT. We appreciate the removal of Requirement R1.5 and R4 and other clarifications from draft 3. 3. ATC's remaining concern for PRC-005-2 is with definition and timelines established in Table 1-5. ATC believes 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. ATC hopes that the SDT will consider these changes.
Response: Thank you for your comments. 1. The SDT considers it important to verify that each breaker trip coil has indeed operated within the established intervals. While breakers may be operated much more frequently at times (and allow the entity to document these operations to address this activity), other breakers may not be called on to operate for many years. 2. The SDT believes that electromechanical devices share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-Based maintenance is an option to increase the intervals if the performance of these devices supports those intervals. 3. The SDT believes that performing these maintenance activities will benefit the reliability of the BES.		
Tri-State G & T Association, Inc. (3)	Ballot Comment - Affirmative	1: Section A.4.2. They are referencing Protection Systems as if they are Facilities in the Applicability section. Facilities are BES Elements, but Protection Systems are not. That needs to be modified somehow. Perhaps the drafting team needs to add another category under Applicability entitled "Protection Systems" and then list which types are included. 2: Maintenance Correctable Issue - This definition seems to be more of a Maintenance Non-Correctable Issue since it can only be resolved by follow-up corrective action. Suggest changing the term. 3: Change Definitions as indicated below: Segment - Protection System components that are identical or share common elements. Consistent performance is expected across the entire population of a Segment. A Segment must contain at least sixty (60) individual components in order to be considered for inclusion in a performance-based PSMP Component -An individual piece of equipment included in the definition of a Protection System., Entities are allowed some latitude to designate their own definitions of a Component. An example of where the entity

Organization	Yes or No	Question 5 Comment
		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. 4: M1 - Why is the document necessary to be “current or updated?” Eliminate “or updated.” 5: The Applicability section needs to be changed, regardless of whether it has been discussed before. Protection Systems are not Facilities.
Response: Thank you for your comments. 1. The standard template allows for two separate sections within Applicability, “Entities” and “Facilities”. The listing under Facilities is describing the applicable facilities to which the Protection Systems are applied, clarified further to indicate that only the Protection Systems on those Facilities are relevant. 2. The definition of maintenance correctable issue has been revised to be clearer. Please see Section 4.1 of the Supplementary Reference Document for additional discussion. The revised definition is: **Maintenance Correctable Issue** – Failure of a component to operate within design parameters such that the deficiency cannot be corrected during the performance of the maintenance activity. Therefore this issue requires follow-up corrective action. 3. The SDT does not believe that your suggested changes add clarity. 4. M1 has been modified as you suggest. 5. The standard template allows for two separate sections within Applicability, “Entities” and “Facilities”. The listing under Facilities is describing the applicable Facilities to which the Protection Systems are applied, clarified further to indicate that only the Protection Systems on those Facilities are relevant.		
Progress Energy		Comments on Draft Standard 1. Table 1-1, 2nd row, 2nd bullet: The comment “(see Table 2)” does not apply to this bullet, but applies to the first bullet. 2. Table 1-3, 2nd row: Need to add “(See Table 2).” Comments on Implementation Plan 1. Section 3a states that “The entity shall be at least 30% compliant on the first day of the first calendar quarter 2 calendar years following applicable regulatory approval” If regulatory approval occurs on January 31, 2012, does this mean that the entity has until December 31, 2014 to be 30% compliant? It might be beneficial to provide an example explaining “calendar year.” Comments on Supplementary Reference

Organization	Yes or No	Question 5 Comment
		1. Table of Contents does not list Section 15.4 2. Page 54, last paragraph, last sentence: “advances that are may be coming” 3. Page 65, 5th paragraph: VLRA should be VRLA 4. Page 67, 4th paragraph, 4th sentence: “typically looking for on the plates” 5. Page 69, 4th paragraph, last sentence: “Grounds because to of the possible” 6. Page 69, 5th paragraph, 2nd sentence: “For example, to do I need” 7. Page 70 5th paragraph, 5th sentence: “A manufacturer of” 8. Page 70 5th paragraph, 6th sentence: “by a third manufacturer’s equipment” 9. Page 71, first line: “(impedance, conductance, and resistance)”

Response: Thank you for your comments.

Draft Standard Comments

1. The Table has been modified as you suggest.

2. The Table has been modified as you suggest.

Implementation Plan Comments

1. The Implementation Plan has been modified for clarity. For the cited example with regulatory approval on January 31, 2012, the entity must be 30% compliant on the first day of the first calendar quarter 24 months following regulatory approvals. Hence, the entity must be 30% compliant on April 1, 2014.

Supplemental Reference Document Comments

1. Changed per your suggestion.

2. Changed per your suggestion.

3. Changed per your suggestion.

4. Changed per your suggestion.

5. Changed per your suggestion.

6. Changed per your suggestion.

7. Changed per your suggestion.

Organization	Yes or No	Question 5 Comment
8. Changed per your suggestion. 9 Changed per your suggestion.		
Dominion Virginia Power		Comments: IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months must implement a policy of two months with one month of grace period thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, Dominion suggests that all battery maintenance intervals expressed as 3 calendar months be changed to 4 calendar months.
Response: Thank you for your comments. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a "grace period" if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" for a discussion about "calendar month". Basically every "3 Calendar Months" means to add 3 months from the last time the activity was performed.		
Santee Cooper		Comments: 1. Santee Cooper does not agree with the expansion of the UFLS and UVLS requirements to include the dc supply. We understand that, in the previous consideration of comments, it is stated that "For UFLS and UVLS, the maintenance activities related to station dc supply and control circuitry are somewhat constrained relative to similar activities for Protection Systems in general." In the table, the requirement for dc supply for UFLS is to verify the station dc supply voltage when the control circuits are verified, which could be 6 or 12 years. It seems like the restraint shown in the requirement, if an indication of the level of need for the verification, is of a much longer timeframe than what would actually happen in the typical operation of a distribution system. Therefore, proof of this verification seems to be of minimal value compared to the extra documentation required due to this now being an auditable maintenance activity. 2. We also agree that maintenance activities with fast intervals, especially the 3 month ones, should be adjusted to 4 months to allow for the actual interval the entities use to be 3 months. Having the requirement at 3 months forces the utilities to schedule even faster (such as every month or 2 months) to ensure compliance.
Response: Thank you for your comments. 1. Section 202 of the NERC Rules of Procedure define "Reliability Standard" as "a requirement to provide for reliable operation of the bulk power system …" The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition.		

Organization	Yes or No	Question 5 Comment
2. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a "grace period" if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" for a discussion about "calendar month". Basically every "3 Calendar Months" means to add 3 months from the last time the activity was performed.		
The Detroit Edison Company		1. Countable Event - This definition should be clarified. As it stands, it appears that if a technician were to adjust the settings on an electromechanical relay - even if it were not outside of the entity's acceptable tolerance - it would need to be classified as a countable event. I would recommend that the definition be limited to repairing or replacing a failed component during the maintenance activity. These activities would address conditions that would potentially cause a Protection System misoperation (either a failure to trip or an unintentional trip). Routine maintenance activities to bring component test values back within tolerance should be excluded from the definition of a Countable Event. These activities are performed to keep the protection systems performance at its most ideal state. In addition, the definition as stated appears to classify battery maintenance activities such as cleaning corrosion, adding water, or applying an equalize charge, as countable events. If this is the intent, I disagree. These are activities that are expected to occur on a regular, routine basis due to the chemical properties of the battery (as described at length in the Supplementary Reference). As such, they should also not be classified as countable events. 2. Table 1-1 and Table 1-5 Based on experience with DECo equipment, a 6 year interval for testing monitored relays and performing tests on the breaker trip coil is substantially shorter than required. Currently, the interval for both is 10 years. This interval lines up both with the Transmission Owner's interval for relay maintenance as well as the maintenance interval for the associated current interrupting devices. I would recommend that these intervals be extended, at minimum, back to the 7 year interval proposed in Draft 2 - if not longer. 3. Table 1-4 (a, b, c, e) - Station dc supply using any type of battery recommend that the maintenance activity to "Verify: Station dc supply voltage" be clarified to state that the voltage should be measured at the positive and negative battery terminals. Until you get to page 72 of the Supplementary Reference, you do not know if this means to check the battery voltage or the bus voltage. The "Station dc supply" could refer to the entire dc system. It needs to be made clear in the table that you are referring to the battery. 4. Also, I noticed that there is no longer a requirement to measure individual cell voltages. I was wondering if you could explain the rationale behind that. Checking for voltages that are out of specification in individual cells helps to identify weak cells that may need to be replaced, if corrective action taken on them does not improve their condition. Individual cell voltage readings, along with ohmic readings, have been an industry standard that I believe many, if not most, companies adhere to. 5. Table 1-4 (a, b, c, d)I recommend eliminating the 3 month requirement. We have found annual inspections to be sufficient in catching problems early enough to take corrective action. Page 30 of the Supplementary

Organization	Yes or No	Question 5 Comment
		Reference states that the SDT believes that routine monthly inspections are the norm. While this may be the case at manned stations, it is not at unmanned stations. The amount of paperwork that would be required to demonstrate compliance is overwhelming and would be an immense burden. I have seen your suggestion in past draft comments of the same nature that if we don't want to do the 3 month inspections, then we should utilize more advanced monitoring. This is not something that can be implemented in a short time frame. It would take years to put all of that technology in place, and is rather cost prohibitive. Furthermore, some of the monitoring technologies that would enable you to forgo the 3 month requirement do not exist yet (to my knowledge). I recommend keeping with the 18 month requirement. If that seems too long, based on past experience I think a 12 month requirement would suffice. 6. Table 1-4 (c) I propose keeping the option to evaluate ohmic values to baseline. 7. Table 1-4 (a, b) For the requirement to evaluate the ohmic values to baseline, is a checkbox stating that you did this sufficient, or would a report/graph/etc listing the actual baseline and current value be required? 8. Table 1-4 (f) The first attribute is regarding high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure. Would a low voltage alarm combined with high voltage shutdown (but not a high voltage alarm) meet this requirement? The high voltage shutdown will shut the charger down in a high voltage condition, and therefore result in a low voltage alarm, so the outcome is the same.

Response: Thank you for your comments.

1.”Tweaking the settings” on a component that is not outside tolerances is not a Countable Event, which is partially defined as “A component which has failed and requires repair or replacement, any condition discovered during the verification maintenance activities in Tables 1-1 through 1-5 which requires corrective action …”. However, as described in Clause 9.2 (Question 4) of the Supplementary Reference Document, a device which is outside tolerances should be considered to have experienced a “calibration failure” and thus has experienced a countable event.

2. If an entity’s experience is that these components require less-frequent maintenance, a performance-based program in accordance with R2 and Attachment A is an option. The intervals were revised after Draft 3 such that the various intervals are multiples of each other, such that entities may establish a systematic PSMP.

3. Your observation that in section 15.4 of “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” the SDT stated that “verification of dc supply voltage is simply an observation of battery voltage” is correct, but the SDT does not agree that the location where voltage should be measured (verified) be contained in PRC-005-2 or the Supplementary Reference document. Due to the variances in topography of dc control circuitry for Protection Systems, a single location for verification of dc supply voltage cannot be specified and must be determined by the Protection System owner.

4. As you correctly stated taking Individual cell voltage readings has been a standard that many companies adhere to. However, this maintenance activity was removed from the standard because it was a “how to requirement”.

5. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a “grace period” if adequate program oversight is exercised, and disagrees that the

Organization	Yes or No	Question 5 Comment
intervals should be extended. See Section 7.1 of the "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" for a discussion about "calendar month". Basically every "3 Calendar Months" means to add 3 months from the last time the activity was performed. 6. In section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" the SDT explains why in Table 1-4 (c) (Station dc supply using NiCad batteries) the option to evaluate ohmic values to baseline is not available. 7. The SDT believes that just providing "a checkbox stating that you did this" is sufficient proof. Section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" provides additional discussion on this topic. However, the SDT is unable to fully predict what evidence may be required by the Compliance Enforcement Authority to demonstrate compliance. 8. "A low voltage alarm combined with high voltage shutdown (but not a high voltage alarm)" would only partially meet the requirement. To ensure that the automatic shutdown of the battery charger for high voltage conditions is achieved, a high voltage alarm must be a component attribute of the monitoring system in order.		
Florida Keys Electric Cooperative Assoc. (1)	Ballot Comment - Negative	Extreme unreasonableness and undue hardships on entities, specifically smaller entities. Just one example is "battery inspections". What is an inspection - simply visual or cell readings? Some entities may have to assign full time battery maintenance duties. Can SCADA monitor DC voltage trends?
Response: Thank you for your comments. In section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" – that was provided for review and comment with PRC-005-2 – details what should be inspected for visual battery cells. The SDT disagrees that the PRC-005-2 with its accompanying Table 1 imposes "extreme unreasonableness and undue hardships on entities, specifically smaller entities" to maintain a reliable Protection Systems. Monitoring the dc voltages via SCADA is an option.		
FirstEnergy		FE offers the following additional comments and suggestions: We do not agree with the wording of requirement R3. The entity is only required to meet the minimum maintenance intervals of the standard as outlined in Tables 1 and 2. We offer a scenario where an entity states that they will go above the standard and maintain relays on a 4 year cycle. The standard, in meeting an adequate level of reliability, sates that this activity must be performed every 6 years. If the entity happened to miss the 4 year timeframe, deciding from a business standpoint to delay the maintenance to the 5th year, an auditor can find the entity non-compliant per the guidance and wording of the requirements in this standard. However, the entity still exceeded an adequate level of reliability by performing the maintenance within 5 years. This scenario would be very unfortunate to the entity that has essentially done their part in providing reliability to the bulk power system, yet they would be punished for not meeting their more stringent timeframes. This standard's guidance and requirements sends an adverse message to industry. It essentially punishes an entity for going above and beyond the standard except on a few rare occasions. If this were to happen, that entity, and possibly others, would not see the value in going above a standard. It would make entities meet the bare minimum requirements, essentially reducing overall system reliability. Therefore, we

Organization	Yes or No	Question 5 Comment
		suggest the following wording for requirement R3: "R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement its PSMP to ensure adherence to the minimum requirements as outlined in Tables 1 and 2, and initiate resolution of any identified maintenance correctable issues."
Response: Thank you for your comments. The Standard requires an entity to implement a PSMP that meets the minimum requirements to the standard. An entity may choose to implement a program that exceeds the requirements.		
City of Farmington (3)	Ballot Comment - Affirmative	FEUS would like to thank the Drafting Team. The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. However, section 4.2 identifies five types of protection systems that the standard is applicable to, but the language of Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). We believe the intent is to have a PSMP for all Protection Systems identified in Section 4.2 and that the language of Requirement 1 may cause confusion or be misleading. We suggest changing the language of Requirement 1 from: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2.
Response: Thank you for your comments. R1 has been modified as you suggest.		
FirstEnergy Energy Delivery FirstEnergy Solutions Ohio Edison Company (1) (3) (4) (5) (6)	Ballot Comment - Affirmative	FirstEnergy appreciates the efforts of the drafting team and supports PRC-005-2. We would also like the team to address our comments and suggestions submitted through the separate comment period.
Response: Thank you for your comments. Please see our responses to your comments submitted with the Formal Comments.		
ITC		1. For Battery System:- Table 1-4(a)o The maximum maintenance interval for the majority of the battery maintenance is listed at "18 calendar months". The current ITC Standard is"once per calendar year and a calendar year is defined as a twelve-month period beginning January 1st and ending December 31st ".

Organization	Yes or No	Question 5 Comment
		ITC would like the maximum maintenance interval at "once per calendar year" 2. Table 1-4(b) o VRLA (Valve Regulated Lead Acid) batteries have an additional inspection at 6 calendar months that includes inspecting the condition of all individual units by measuring the battery cell/unit internal ohmic values. This is in addition to the "18 calendar months" inspection. ITC would like to be consistent with the VLA (Vented Lead Acid) batteries and have only one internal ohmic value inspection once per calendar year. 3. For Battery System:- Table 1-4(a) o The maximum maintenance interval for the majority of the battery maintenance is listed at "18 calendar months". The current ITC Standard is "once per calendar year and a calendar year is defined as a twelve-month period beginning January 1st and ending December 31st ". ITC would like the maximum maintenance interval at "once per calendar year" 4. Table 1-4(b) VRLA (Valve Regulated Lead Acid) batteries have an additional inspection at 6 calendar months that includes inspecting the condition of all individual units by measuring the battery cell/unit internal ohmic values. This is in addition to the "18 calendar months" inspection. ITC would like to be consistent with the VLA (Vented Lead Acid) batteries and have only one internal ohmic value inspection once per calendar year. 5. Auxiliary Relays: ITC does not agree with the 6 year interval for Aux relays in the trip circuit. Although they are EM relays they are simple and have very few moving parts. We believe the maintenance period for auxiliary relays should be 12 years and they should be in conjunction with the control circuit. We recognize that Draft 4 only includes auxiliary relays that are directly in the trip path. That is an improvement in Draft 4. In general, auxiliary relays are very reliable; only certain relay types have been proven to be problematic. A known relay type (HEA) has been proven to be problematic if not exercised frequently. The standard should not require a 6 year interval period for all other auxiliary relays. We believe problematic relays should be addressed through use of a NERC Alert process. Don't cut down the tree for a bad apple.

Response: Thank you for your comments.

1. In choosing the 18 calendar month interval for the maximum maintenance interval for the maintenance activities of table 1-4(a) the SDT was aware that the majority of these activities are recommended to be performed in IEEE 450 "Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications "at the Yearly inspection. The SDT does not agree that "once per calendar year" would be a more appropriate interval for these activities but notes that entities may choose to perform required activities more frequently than the maximum intervals expressed in the Tables.

Organization	Yes or No	Question 5 Comment
2. In section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" – that was provided for review and comment with PRC-005-2 explaining why the for VRLA battery systems (Table 1-4(b)) the maximum maintenance intervals and maintenance activities cannot be consistent with the intervals and activities of VLA battery systems (Table 1-4(a)). 3. In choosing the 18 calendar month interval for the maximum maintenance interval for the maintenance activities of table 1-4(a) the SDT was aware that the majority of these activities are recommended to be performed in IEEE 450 "Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Stationary Applications "at the Yearly inspection. However, the SDT has considered that IEEE 450 presents these activities as recommended activities in a vacuum, without considering other activities that are being performed at the 3-calendar-month interval and has established the 18-calendar-month interval to comport to the most aggressive intervals being used in common practice. The SDT does not agree that "once per calendar year" would be a more appropriate interval for these activities but notes that entities may choose to perform required activities more frequently than the maximum intervals expressed in the Tables. 4. Section 15.4 of "PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ" (question – "What are cell/unit internal ohmic measurements "– that was provided for review and comment with PRC-005-2 – explains why the for VRLA battery systems (Table 1-4(b)) the maximum maintenance intervals and maintenance activities cannot be consistent with the intervals and activities of VLA battery systems (Table 1-4(a)). 5. The SDT believes that electromechanical devices share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-Based maintenance is an option to increase the intervals if the performance of these devices supports those intervals. If an entities' experience is that these components require less-frequent maintenance, a performance-based program in accordance with R3 and Attachment A is an option.		
Manitoba Hydro		-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
Manitoba Hydro (1) (3) (5) (6)	Ballot Comment - Negative	Manitoba Hydro is voting negative for the following reasons: -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 (removing an asset in a time of constraint). 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 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 reliability without risking non-compliance.
Response: Thank you for your comments. "Grace Periods" within the standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the		

Organization	Yes or No	Question 5 Comment
intervals within the standard.		
Georgia System Operations Corporation (3)	Ballot Comment	GSOC supports comments submitted by Georgia Transmission Corporation
Response: Thank you for your comments. Please see the SDT response to the comments submitted by Georgia Transmission Corporation.		
Electric Market Policy		IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months must implement a policy of two months with one month of grace period thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, Dominion suggests that all battery maintenance intervals expressed as 3 calendar months be changed to 4 calendar months.
Response: Thank you for your comments. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a “grace period” if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month”. Basically every “3 Calendar Months” means to add 3 months from the last time the activity was performed.		
Alliant Energy Corp. Services, Inc. (4)	Ballot Comment - Negative	1. If PRC-005-2 is going to incorporate PRC-008 (UFLS) and PRC-011 (UVLS) the Purpose needs to be revised to include Distribution Protection Systems designed to protect the BES. 2. We do not believe a distribution relaying system, designed to protect the distribution assets, that may open a transmission element (ie; breaker failure) should be considered part of the BES Protection System. R1 should add the following sentence “Distribution Protection Systems intended solely for the protection of distribution assets are not included as a BES Protection System, even if they may open a BES Element.”
Response: Thank you for your comments. 1. Section 202 of the NERC Rules of Procedure define “Reliability standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition. UFLS and UVLS are described in the Applicability as being included within the Protection System addressed within the standard if they are applied per other NERC Standards. 2. Section 202 of the NERC Rules of Procedure define “Reliability standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirement, as written, supports this.		

Organization	Yes or No	Question 5 Comment
Exelon		1. In response to Exelon's comments provided to drafts 1, 2, and 3 of PRC-005, the SDT did not explain why a conflict with an existing regulatory requirement is acceptable. The SDT previously responded that a conflict does not exist and that the removal of grace periods simply is there to comply with FERC Order directive 693. In response to draft 3 of PRC-005, the SDT stated that "If several different regulatory agencies have differing requirements for similar equipment, it seems that the entity must be compliant with the most stringent of the varying requirements. In the cited case, an entity may need to perform maintenance more frequently than specified within the requirements to assure that they are compliant." Again this does not explain why a conflict with an existing regulatory requirement is acceptable. This response does not answer or address dual regulation by the NRC and by the FERC. Specifically, the request has not been adequately considered for an allowance for NRC-licensed generating units to default to existing Operating License Technical Specification Surveillance Requirements if there is a maintenance interval that would force shutting down a unit prematurely or become non-compliant with PRC-005. Therefore, Exelon again requests that the SDT communicate with the NRC and with the FERC to ensure a conflict of dual regulation is not imposed on a nuclear generating unit without the necessary evaluation. In addition, the SDT still did not fully evaluate or address the concern related to the uniqueness of nuclear generating unit refueling outage schedules. 2. Although Exelon Nuclear agrees with the SDT that the maximum allowed battery capacity testing intervals of not to exceed 6 calendar years for vented lead acid or NiCad batteries (not to exceed 3 calendar years for VRLA batteries) could be integrated within the plant's routine 18 month to 2 year interval refueling outage schedule, the SDT has not considered that nuclear refueling outages may be extended past the 18 month to 2 year "normal" periodicity. There are some unique factors related to nuclear generating units that the SDT has not taken into consideration in that these units are typically online continuously between refueling outages without shutting down for any other required maintenance. Historically, generating units have at times extended planned refueling outage shutdown dates days and even weeks due to requests from transmission operations, fuel issues and electrical demand. Without the grace period exclusion currently allowed by existing maintenance programs, a nuclear plant will be forced to either extend outage duration to include testing on an every other refueling outage (i.e., every four years to ensure compliance for a typical boiling water reactor) or leave the testing on a six year periodicity with the vulnerability of a forced shut down simply to perform maintenance to meet the six year periodicity or a self report of non-compliance. To ensure compliance, the nuclear industry will be forced to schedule battery testing on a four year periodicity to ensure the six year periodicity is met, thus imposing a requirement on nuclear generating units that would not apply to other types of generating units. The SDT response to this question in draft 3 is that "(t)he 18-month (and shorter) interval activities are activities that can be completed without outages - primarily inspection-related activities. An entity may need to perform maintenance more frequently than specified within the requirements to assure that they are compliant." Respectfully Exelon requests that the SDT review and evaluate the concern.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td colspan="3">Response: Thank you for your comments.

1. It appears that the SDT’s response was mis-understood. The SDT intended that the response be understood as” in order to be compliant with all requirements, regardless of the different agencies imposing those requirements, the entity will likely have to be compliant with the most stringent of the requirements”. Regarding PRC-005-2, an entity must be compliant with the included requirements, even if they are more stringent than other regulatory requirements.

2. The SDT believes that the activities addressed in the comment can be integrated with the 18-24 month plant refueling outage. This may result in the activities being performed more frequently than specified.</td></tr>
<tr><td>Entergy (3)

Entergy Services, Inc. (6)</td><td>Ballot Comment - Negative</td><td>In Section 4.2, ‘Facilities’ add the following subsection 4.2.6: Protection Systems for generating units in extended forced outage or in inactive reserve status are excluded from the requirements of this standard. However, the required maintenance and testing of the Protection Systems at these units must be completed prior to connecting the units to the Bulk Electric System (BES). Reason for the above comment: The above units are not connected to the BES and therefore do not affect the reliability of the BES. However, to ensure the reliability of the BES, required maintenance and testing of the Protection Systems at these units must be completed prior to connecting them to the BES.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Please refer to Compliance Application Notice CAN-0011, footnote 5, which states, “The registered entity’s Protection System maintenance and testing program is only applicable for Protection System devices in service …” The SDT believes that this guidance will remain durable for PRC-005-2.</td></tr>
<tr><td>Entergy Services</td><td></td><td>In Section 4.2, “Facilities” add the following subsection 4.2.6: Protection Systems for generating units in extended forced outage or in inactive reserve status are excluded from the requirements of this standard. However, the required maintenance and testing of the Protection Systems at these units must be completed prior to connecting the units to the Bulk Electric System (BES).

Reason for the above comment: The above units are not connected to the BES and therefore do not affect the reliability of the BES. However, to ensure the reliability of the BES, required maintenance and testing of the Protection Systems at these units must be completed prior to connecting them to the BES.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments. Please refer to Compliance Application Notice CAN-0011, footnote 5, which states, “The registered entity’s Protection System maintenance and testing program is only applicable for Protection System devices in service …” The SDT believes that this guidance will remain durable for PRC-005-2.</td></tr>
<tr><td>MRO's NERC Standards Review Subcommittee</td><td></td><td>In the checkbox for Requirement R3 please change the wording to read, “Maintenance Correctable Issue - Failure of a component to operate within design parameters such that it cannot be restored to functional order by repair or calibration during performance of the initiating on-site activity. Therefore this issue requires follow-</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		up corrective action.”
Response: Thank you for your comments. The definition of maintenance correctable issue has been revised to be clearer: Maintenance Correctable Issue – Failure of a component to operate within design parameters such that the deficiency cannot be corrected during the performance of the maintenance activity. Therefore this issue requires follow-up corrective action.		
Bonneville Power Administration		1. In the header of Tables 1-1, 1-2, 1-3, and 1-5 there is a note that says "Table requirements apply to all components of Protection Systems except as noted." Since each table only applies to the specific component type shown in the header, we do not understand what this note means. The definition given for component only makes the note more confusing. Please clarify the note. 2. Additionally, BPA is voting no during this round due to an issue with the Applicability Section and Section 4.2. Once this issue is clarified, BPA would be in support of a yes vote. Issue: Section 4.2 Facilities lists 5 separate items that the standard is applicable for (4.2.1. - 4.2.5). However Requirement 1 uses language that only addresses one of the items (4.2.1). There is no language contained anywhere within any of the requirements in PRC-005-2 that apply to the types of protection systems described in Applicability Sections 4.2.2 - 4.2.5. Therefore, it could be argued that this leaves it open to interpretation as to whether UFLS/UVLS/SPS are addressed by R1.In the NOPR (Â¶ 105), FERC states that “the Requirements within a standard define what an entity must do to be compliant” Further, in Order 693 (Â¶ 253) FERC explicitly states that “compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement”. Given this, then from a compliance perspective, the actual applicability of the standard appears to not be as broad as intended. We ask that this issue be resolved by modifying the language in R1 in a manner that explicitly encompasses all types of protection systems to which it is intended to be applied.
Response: Thank you for your comments. 1. In Table 1-1, for example, this note means that all activities apply to all protective relay components unless specifically differentiated within individual table entries. Because Tables 1-1, 1-2, and 1-3 do not include any additional differentiation within the table, the note was removed from these tables in consideration of your comment. 2. The R1 requirement has been revised in consideration of your comments.		
JEA (3)	Ballot Comment - Negative	JEA maintains testing of lockout relays will have major reliability impact to the JEA system.

Organization	Yes or No	Question 5 Comment
Response: Thank you for your comments. The SDT believes that electromechanical devices share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-Based maintenance is an option to increase the intervals if the performance of these devices supports those intervals.		
Tri-State G&T		1. M1 - Why is the document necessary to be "current or updated?" Eliminate "or updated." 2. R1 VSL - Second item in Severe VSL is not addressed in any lower VSL. Should there also be a comparable violation in Lower and Moderate? 3. R2 VSL - Keep the comment about the redundancy in Lower VSL and High VSL for clarifying the difference between the two.
Response: Thank you for your comments. 1. M1 has been revised as suggested and the phrase, "or updated" has been removed 2. The VSL for R1 has been revised to add phased VSLs for Moderate and High related to this item. 3. The High VSL has been modified from three years to four years.		
Ameren		1. Measure M3 on page 5 should apply to 99% of the components. "Each __shall have evidence that it has implemented the Protection System Maintenance Program for 99% of its components and initiate" 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 in that valuable resources will be distracted from other duties. 2. Define BES perimeter in accordance with Project 2009-17 Interpretation. Facilities Section 4.2.1 "or designed to provide protection for the BES" needs to be clarified so that it incorporates the latest Project 2009-17 interpretation. The industry has deliberated and reached a conclusion that provides a meaningful and appropriate border for the transmission Protection System; this needs to be acknowledged in PRC-005-2 and carried forward. The BOT adopted this 2/17/2011. 3. Battery inspection every 4 months is sufficient. IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months due to storms and outages must set a target interval of two months thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, we also suggest that all intervals expressed as 3 calendar months be changed to 4 calendar months.

Organization	Yes or No	Question 5 Comment
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. 2. The referenced interpretation relates to a quasi-definition of “transmission Protection System”, and in the context of the approved PRC-004-1 and PRC-005-1, presents a consistent context for this term. However, the interpretation was constrained to not introduce any requirements or applicability not already included within the approved standards. PRC-005-2 does not use this term, and expands upon the applicability in the interpretation to address what seems to the SDT to be an appropriate applicability for PRC-005-2. The applicability of the interpretation to PRC-004 is not affected by PRC-005-2. 3. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a “grace period” if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month”. Basically every “3 Calendar Months” means to add 3 months from the last time the activity was performed.		
Madison Gas and Electric Co. (4)	Ballot Comment - Affirmative	MGE is voting affirmative with the following recommendation to the definition of Maintenance Correctable Issue. Maintenance Correctable Issue - Failure of a component to operate within design parameters such that it cannot be restored to functional order by repair or calibration during performance of the "initiating" on-site activity. Therefore this issue requires follow-up corrective action. The removal of the word “initial” will cause less confusion because the industry does not understand if this is initial (commissioning) or is initial used as when a component requires repair. Recommend “initiating” replace “initial”.
Response: Thank you for your comments. The definition of maintenance correctable issue has been revised to be clearer: Maintenance Correctable Issue – Failure of a component to operate within design parameters such that the deficiency cannot be corrected during the performance of the maintenance activity. Therefore this issue requires follow-up corrective action.		
Arizona Public Service Company		NERC continues to be too prescriptive in the standard. For example, Table 1-4(a) requires battery verifications and inspection every three months. We have been performing similar tests every four months for over a decade, with no adverse consequences. Although FERC Order 693 directs NERC to establish maximum allowable intervals, the maximum interval must be “appropriate to the type of protection system and its impact on the reliability of the Bulk-Power System.” (Order 693 at 1475)The Standard Drafting Team (SDT) has not demonstrated a mechanism that connects the maximum maintenance interval with its impact on the reliability of the Bulk-Power System. An example can be found on the bottom of page 18 and the top of page 19 of the Consideration of Comments on Protection System Maintenance [Project 2007-17] for draft 3. Although the commenting organization provided a concrete example of successful maintenance under a longer interval, the Standards Drafting Team commented that it “believes that 18-months is the proper interval for this activity.” (Emphasis added) An organization cannot challenge the SDT’s beliefs, only facts. The basis for each maximum maintenance interval, with appropriate linkage to its impact on the reliability of the Bulk-

Organization	Yes or No	Question 5 Comment
		Power System, needs to be published and voted upon so that factual based proposals to modify the maximum interval can be rationally challenged.
Response: Thank you for your comments. The basis for the intervals established within the standard is described throughout the Supplementary Reference document.		
Northern Indiana Public Service Co. (3)	Ballot Comment - Negative	One of our concerns is that, while the present standard is 2 pages and is the most highly violated and fined standard, the new proposed standard is 22 pages, the implementation plan is 4 pages and the Supplemental FAQ document is 87 pages.
Response: Thank you for your comments. The SDT has established maximum allowable intervals in accordance with FERC Order 693. Additionally, the SDT has addressed many of the common program-related causes of observed violations, and has provided the Supplementary Reference and FAQ to assist entities in implementing their program.		
PJM Interconnection, L.L.C. (2)	Ballot Comment - Negative	PJM has a general problem with how this current draft defines "protection system". The issue is that PJM believes the standard should only apply to Protection relays that are designed to protect the BES. It should not apply to relays that protect the asset itself.
Response: Thank you for your comments. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements as written directly support this definition.		
Western Area Power Administration		Please explain or clarify the term “mitigating devices” used in Table 1-5 Control Circuitry, Page 19. This term is not well defined in the industry and not easily understood as “interrupting device” or “circuit breaker.”
Response: Thank you for your comments. This term is primarily focused on Special Protection Systems, where they may perform some activity other than “interrupt” to address their design objectives.		
Shermco Industries		1. Please provide clarification on "Communications" in regards to the following: If our customers are utilizing Schweitzer SEL311 relays and utilizing the fiber for transfer trip, is this considered a communications circuit? Our experiences in regards to testing these devices that have transfer trips out into a main substation that could affect a main ring tie or open a major 138kV loop, are that the T&D utilities will not allow us to perform these tests and trip their breakers. Therefore, what is required to satisfy testing? 2. In regards to Function / Trip testing, if we have a sudden pressure device, this is considered an auxiliary relay and the sudden pressure relay itself is not required to be tested. However, the trip path is required to be tested for DC tripping, if it directly trips the breaker feeding the BES, on the DC Control verification

Organization	Yes or No	Question 5 Comment
		testing. Please clarify if this is correct.
Response: Thank you for your comments. 1. The fiber you indicate is a relay communications circuit. The SEL311 monitors the condition of the fiber. It will provide an alarm on loss of communications. If this alarm is not monitored then the entity will be required to check it every 3 months and verify it is still operational. If the communications alarm is brought back to the control center, and the error rate or pilot signal is verified continuously, the interval will be 12 years. 2. Yes, this is correct.		
ExxonMobil Research and Engineering		1. PRC-005-2 is a highly prescriptive standard that prevents small entities from establishing a risk-based approach to protective system maintenance that is commonly used in other industry sectors and forces the small entity to utilize the time-based program. Many registered entities do not have a population size of 60 for each type of protective device. However, they do possess historical records that can be used to calculate the mean time between failures for each equipment type that adequately reflects the service conditions in which the equipment is installed. The SDT should consider allowing registered entities to utilize historical records in their supporting documentation for defining a performance based program. 2. Additionally, by restricting populations by manufacturer model, as referenced in PRC-005-2 Attachment A, the Standard Drafting Team is bordering on anti-competitive behavior as those entities that utilize performance-based programs may be discouraged to utilize alternative suppliers because utilization of a time-based maintenance program on the alternative supplier's equipment may present a cost-benefit analysis hurdle that the supplier of the equipment is not able to overcome. 3. Lastly, the SDT has chosen not to provide a tolerance band for the maximum maintenance intervals it defines in its time-base program. Given that the SDT has not provided sound technical justification (i.e. a study, industry recommended practice, etc.), the SDT should reconsider its stance on providing a tolerance band on the time intervals specified in the time-based program. What is the increase in risk owned by an entity when a protective device is tested at the 6 year and 30 day mark instead of the 6 year mark?
Response: Thank you for your comments. 1. If the historical records fully address the criteria in Attachment A, they would be useful in establishing the basis for a performance-based maintenance program. If the population is not in accordance with the definition of segment in Attachment A, the SDT does not believe that the entity has a statistically-significant sample on which to base a PBM. 2. In order to properly apply a performance-based maintenance program, the components within a segment must be such that they will exhibit similar behavior. Similarly-functioning components from different manufacturers will likely not satisfy this criterion. If an entity does not have sufficient component populations to apply performance-based maintenance, they must revert to time-based maintenance per the Tables or find another entity with whom they can aggregate		

Organization	Yes or No	Question 5 Comment
components within a performance-based maintenance program. Please see Section 9 of the Supplementary Reference Document for a discussion regarding aggregating components between entities within a performance-based maintenance program. 3. There may be minimal additional risk for missing the required interval by only a small amount. However, "grace periods" within the standard are not measurable, and would probably lead to persistently increasing intervals. However, an entity may establish an internal program with grace-period allowance, as long as the entire program (including grace periods) does not exceed the intervals within the standard. Also, this concern is only a practical one if an entity is persistently maintaining its Protection System components at the very end of each maximum allowable interval.		
Luminant		The red-lined version did not appear to agree with the clean copy. In reading the "red lined" document it appears that R3 was intended to be "Each Transmission Owner, Generation Owner, and distribution Provider shall implement and follow its PSPM and initiate resolution of any identified maintenance correctable issues."
Response: Thank you for your comments. The red-lining tools in Microsoft Word can sometimes be misleading, but the red-line is provided in an effort to illustrate the changes made to the document. We recommend that the entity use the "clean" version in order to see the final resulting text.		
MidAmerican Energy Company		Requirement R3 of the standard discusses resolution of "identified maintenance correctable issues". M3 requires evidence of "resolution of Maintenance Correctable Issues". The definition of Maintenance Correctable Issue in the standard includes "during performance of the initial on-site activity". The "initial on-site activity" seems to imply that the corrective steps that need to be tracked are those resulting from the periodic testing that is done for compliance with the standard. It is not clear if the SDT meant to require that records be kept of any required maintenance that is done as a result of a discovered problem or failure that is not identified during the periodic testing.
Response: Thank you for your comments. The SDT has considered that, while some maintenance correctable issues may be completed very quickly, others may take an extended period (perhaps even several years) to complete effectively, during which time the degraded system must be reported and reflected within the operation of the BES in accordance with other standards. The SDT is concerned that the entity will not be able to record the maintenance activity as "complete" during the scheduled interval for these more extended activities to "correct"; therefore, the SDT has opted to require only that the entity initiate correction of maintenance correctable issues and rely on the operating focus on the degraded system to ensure that they are completed. The definition of maintenance correctable issue has been revised, though, to be clearer. Maintenance Correctable Issue – Failure of a component to operate within design parameters such that the deficiency cannot be corrected during the performance of the maintenance activity. Therefore this issue requires follow-up corrective action.		
Consumers Energy (5)	Ballot Comment - Negative	While most of the changes are quite good, I believe R3 may not be what was intended. R3 concludes with "initiate resolution of any identified maintenance correctable issues." My copy of Webster's Dictonary defines initiate as "to set going : start". Thus to meet R3, I need never order a replacement component I just need to write a purchase order (it's the start of the process). If rewiring is needed, I only need to write a maintenance order, rather than sending out an electrician with tools and wire. I believe reliability would be better served to

Organization	Yes or No	Question 5 Comment
		require resolution of the problem rather than just starting a process to begin work.
Response: Thank you for your comments. The SDT has considered that, while some maintenance correctable issues may be completed very quickly, others may take an extended period (perhaps even several years) to complete effectively, during which time the degraded system must be reported and reflected within the operation of the BES in accordance with other standards. The SDT is concerned that the entity will not be able to record the maintenance activity as "complete" during the scheduled interval for these more extended activities to "correct"; therefore, the SDT has opted to require only that the entity initiate correction of maintenance correctable issues and rely on the operating focus on the degraded system to ensure that they are completed.		
Constellation Energy Commodities Group (6) Constellation Power Source Generation, Inc. (5)	Ballot Comment - Negative	1. R3 is vague and can be easily interpreted in a variety of ways. For example, "initiate resolution" may mean closing a work order on a correctable issue or it may mean simply to create a work order with the intent of closing it out. The difference is not just in compliance evidence but it potentially allows an auditor to interpret the requirement to state that closed work orders should be completed in a timely manner. 2. Lastly, the technical man power and compliance documentation needed to implement a performance based protection system maintenance program are so onerous that it is highly unlikely that any entity would use it."
Response: Thank you for your comments. 1. The SDT has considered that, while some maintenance correctable issues may be completed very quickly, others may take an extended period (perhaps even several years) to complete effectively, during which time the degraded system must be reported and reflected within the operation of the BES in accordance with other standards. The SDT is concerned that the entity will not be able to record the maintenance activity as "complete" during the scheduled interval for these more extended activities to "correct"; therefore, the SDT has opted to require only that the entity initiate correction of maintenance correctable issues and rely on the operating focus on the degraded system to ensure that they are completed. The definition of maintenance correctable issue has been revised to be clearer. Maintenance Correctable Issue – Failure of a component to operate within design parameters such that the deficiency cannot be corrected during the performance of the maintenance activity. Therefore this issue requires follow-up corrective action. 2. The SDT understands that the requirements to establish and operate a performance-based PSMP may be beyond what many entities will wish to pursue. However, these are provided for the use of those entities who wish to make use of the analytical resources to optimize their field maintenance.		
MISO Standards Collaborators		1. R3 speaks of a Maintenance Correctable Issue and implementing your Protection System Maintenance Program (PSMP). In the definition of Maintenance Correctable Issue, it states "...of the initial on-site activity". The intent seems to be that during any maintenance activity, and something is found not working properly, you should repair it. Some may look at the word "initial" as during the commissioning of a facility. We recommend the SDT delete the word "initial" to cause less confusion. 2. We recommend the SDT change the text of Standard PRC-005-2 - Protection System Maintenance Table

Organization	Yes or No	Question 5 Comment
		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 alternately, "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). 3. We recommend the SDT 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. 4. 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. 5. We recognize the substantial efforts and improvements to PRC-005-2 that have been made and appreciate the dedicated work of the SDT. We appreciate the removal of Requirement R1.5 and R4 and other clarifications from draft 3. 6. Our remaining concern for PRC-005-2 is with definition and timelines established in Table 1-5. 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 hope that

Organization	Yes or No	Question 5 Comment
		the SDT will consider these changes.
Response: Thank you for your comments. 1. The word, "initial" is intended to emphasize that an identified concern becomes a Maintenance Correctable Issue when the entity is not able to immediately resolve it, and must return to correct the problem. The definition of maintenance correctable issue has been revised to be clearer. Maintenance Correctable Issue – Failure of a component to operate within design parameters such that the deficiency cannot be corrected during the performance of the maintenance activity. Therefore this issue requires follow-up corrective action. 2. The SDT considers it important to verify each breaker trip coil will indeed operate within the established intervals. While breakers may be operated much more frequently at times (and allow the entity to document these operation to address this activity), other breakers may not be called on to operate for many years. 3. The SDT believes that electromechanical devices contain moving parts and share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-Based maintenance is an option to increase the intervals if the performance of these devices supports those intervals. 4. The SDT believes that performing these maintenance activities will benefit the reliability of the BES. 5. Thank you. 6. The SDT believes that performing these maintenance activities will benefit the reliability of the BES.		
NERC - EA & I		Recommend entities be explicitly required to document the Relay Maintenance Program in one document. Many entities presently maintain their Protection Maintenance Program in several documents, such as one for relays, one for batteries, etc. This complicates compliance review and contributes to non-compliance since personnel in different departments writing these have different levels of understanding of NERC standards. Separate documents also allow inconsistencies to slip in. Recommend Requirement 1 to changed to the following to address this problem. "Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP), RECORDED AND UPDATED AS A SINGLE DOCUMNET for its Protection Systems designed to provide protection for BES Element(s). "
Response: Thank you for your comments. The SDT believes that, because of the diversity of different entities and their business arrangements that such a requirement could serve to decrease the quality of an entity's PSMP, particularly for a vertically-integrated entity that includes several of the specified Applicable Entities. For example, the Generator Owner and Transmission Owner are likely to have significant differences for very good reasons.		
Florida Municipal Power Agency (4) (5) (6)	Ballot Comment - Negative	1. Section 4.2.1 states that the Standard is applicable to "Protections Systems designed to provide protection BES Elements." Section 15.1 of the Supplementary Reference Document defines the scope as those "devices that receive the input signal from the current and voltage sensing devices and are used to isolate a faulted element of the BES." These two statements are not exactly equivalent, and in fact, are in conflict

Organization	Yes or No	Question 5 Comment
Florida Municipal Power Pool (6)		with the Interpretation of PRC-004-1 and PRC-005-1 for Y-W Electric and Tri-State, Approved by the Board of Trustees on February 17, 2011. 2. Section 4.2.1 should be changed to “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 referenced interpretation relates to a quasi-definition of “transmission Protection System”, and in the context of the approved PRC-004-1 and PRC-005-1, presents a consistent context for this term. However, the interpretation was constrained to not introduce any requirements or applicability not already included within the approved standards. PRC-005-2 does not use this term, and expands upon the applicability in the interpretation to address what seems to the SDT to be an appropriate applicability for PRC-005-2. The applicability of the interpretation to PRC-004 is not affected by PRC-005-2. 2. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements as written directly support this definition.		
US Army Corps of Engineers		1. Section 4.2.5.4 - please clarify generator connected station service transformer. We believe this to mean a station service transformer with no breaker between the transformer and the generator bus. 2. R3 - the term 'initiate resolution' is vague and needs to be further defined. Does this mean putting in a work order or is further action required. 3. Data Retention: The proposed standard clarifies that two of the most recent records of maintenance are to be retained to demonstrate compliance with the prescribed maintenance intervals. When equipment is replaced, the reference information indicates that the information associated with the original equipment must be retained to show compliance with the standard until the performance with the new equipment can be established. This is not explicitly stated in the requirements and warrants a comment.
Response: Thank you for your comments. 1. The commenter is correct. 2. The SDT has considered that, while some maintenance correctable issues may be completed very quickly, others may take an extended period (perhaps even several years) to complete effectively, during which time the degraded system must be reported and reflected within the operation of the BES in accordance with other standards. The SDT is concerned that the entity will not be able to record the maintenance activity as “complete” during the scheduled interval for these more extended activities to “correct”; therefore, the SDT has opted to require only that the entity initiate correction of maintenance correctable issues and rely on the operating focus on the degraded system to ensure that they are completed. The definition of maintenance correctable issue has been revised to be clearer. Maintenance Correctable Issue – Failure of a component to operate within design parameters such that the deficiency cannot be corrected during the		

Organization	Yes or No	Question 5 Comment
performance of the maintenance activity. Therefore this issue requires follow-up corrective action. 3. The data retention section is stated to describe what an entity must do to demonstrate compliance to an auditor on a persistent basis. The additional clarification in the Supplemental Reference Document is provided to share the experiences of SDT members with other entities, and to suggest a possible effective practice.		
Public Utility District No. 1 of Lewis County (5)	Ballot Comment - Negative	Standard does not recognize the affects and great burdens to smaller utilities that have limited staff and great distance to travel out west. Generally, our facilities to not affect the BES. We believe that the battery testing requirements are overkill. The intervals for testing should be placed at minimum of 2 or 3 years
Response: Thank you for your comments. The activities involved in the 3-calendar-month maintenance intervals all relate to inspection-type activities of unmonitored battery systems. The SDT believes that an entity may schedule activities for a 3-calendar-month interval without a “grace period” if adequate program oversight is exercised, and disagrees that the intervals should be extended. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month”. Basically every “3 Calendar Months” means to add 3 months from the last time the activity was performed. As for the other shorter-duration activities, the SDT believes that all of these activities, at the specified intervals, are necessary to assure reliability. From the experience of the SDT members, and as supported by various IEEE Standards, it seems clear that delaying the battery maintenance activities to 2-3 years would be detrimental to the reliability of the BES.		
AtCO Electric ltd		1. Table 1-2: the requirement for 12 calendar year verification for the channel and essential signals’ performance should be removed. We do not see benefit in the maintenance activities under level 2 (the 12 calendar year requirement) and suggest merging it with level 3 (the “no periodic maintenance specified” requirement). The “loss of function” alarm, will be considered as a countable event to fall under requirement R3 and dealt as maintenance correctable issue. 2. Table 1-5: the requirement of 6 calendar year verification for electrical operation of electromechanical lockout and/or tripping auxiliary devices should be revisited, considering that: ” It is not feasible to exercise a lockout relay during maintenance due to high risk to the in-service facility, as well as the complexity of lockout relay connections and protection schemes. Instead, we propose a DC ring test, which verifies the continuity of control circuitry and eliminates the risk impact of lockout or auxiliary tripping device operations.” The interval is too frequent. The requirement would become achievable if the 6 calendar year frequency were increased to 12 calendar years, to be in line with microprocessor relay maintenance frequency
Response: Thank you for your comments. 1. Though a channel with continuous alarming may not be in an alarm state during a quiescent state, the alarm function alone does not identify if the channel will fail during fault conditions. Fault noise level and, fault location impact a channels’ noise immunity margin. The activities are specified are to ensure reliable		

Organization	Yes or No	Question 5 Comment
performance of the communication channel. 2. The SDT believes that performing these maintenance activities will benefit the reliability of the BES.The SDT believes that electromechanical devices with moving parts share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-Based maintenance is an option to increase the intervals if the performance of these devices supports those intervals.		
CPS Energy		1. Table 1-5 The new standard requires that every 6 years it is verified that “each trip coil is able to operate the breaker,”. The supplementary reference states that this requirement can be met by tracking real-time fault-clearing operations on the circuit breakers. With transmission breakers typically having dual trip coils, how can tracking real-time operations meet this requirement? Would a breaker operations where relays in both the primary and secondary trip coils indicated operation be sufficient or would some type of trip coil monitoring that showed coil energization be needed? 2. Additionally, regarding the verification of all trip paths of the trip circuit. If a microprocessor relay is used to trip a breaker, and two contacts are paralleled on the relay through a single test switch for breaker tripping, would it be necessary to verify each contact independently or could an assertion of both contacts through the test switch be adequate? In this instance, the functionality of each contact would be fully identical. 3. Table 1-2A 3-month inspection is required for communications equipment that does not have “continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function” has to be verified that the communication equipment is “functional” with a 3-month site visit. Would a carrier on-off system, that did not perform periodic check back testing, but did have an alarm contact (loss of power, failure, etc.) that was monitored through SCADA would need to have a 3-month inspection? According to the supplemental reference, this inspection should be to verify that the equipment is “operable through a cursory inspection and site visit”. It sounds as if this cursory inspection and site visit would accomplish the same as the alarm contact. It does not appear that end-end functional testing of the blocking signal is required by what is provided in the supplemental reference. Is this correct? 4. Table 1-3 - The maintenance activity for the 12 calendar year testing should include a little more specificity. It should have something stating the values provided to the relay are accurate. I know that this discussed in the supplemental reference, but requirement in Table1-3 sounds as if any relay that measured for loss of signal, such as a loss-of-potential function, would be sufficient when the purpose to verify that the signal not only gets to the relay but also has some accuracy as needed by the application of the relay.
Response: Thank you for your comments. 1. If you are able to independently track both trip coils via real-time operations tracking, you could use this tracking to address this activity. If not, you will likely need to perform focused maintenance activities.		

Organization	Yes or No	Question 5 Comment
2. This would be adequate. 3. This is not correct. As you indicate, the 3 month check for unmonitored relay channels is to verify that the channel is functional. For a guard signal, a visual inspection will indicate if a guard or pilot signal is being received. A blocking channel can only be verified by either a checkback test or an end to end signal check. A visual check that the equipment is not failed does not indicate that the channel medium or auxiliary devices are still intact. We will revise the supplementary reference to clear this up (See Section 15.5.1, question “What is needed for the 3-month inspection of communications-assisted trip scheme equipment?”). 4. If the voltage and current signals are measured by the relay and verified to be correct, this would satisfy the required activity in the Table. Please note that, in the definition of Protection System Maintenance Program, “verify” means, “determine that the component is functioning correctly”.		
NextEra Energy		Thank you for your diligent efforts in writing the draft standard. The draft standard and associated documents are well written and we believe, after approval, will be instrumental to improving the reliability of the BES. We have the following specific comments: a. The maximum maintenance interval of unmonitored Vented Lead-Acid (VLA) batteries should be changed from 3 calendar months to 12 calendar months. Today’s lead-calcium and lead-selenium-low antimony batteries do not have rapid water loss as compared to the legacy lead-antimony batteries. FPL’s operating experience has shown that electrolyte in today’s VLA cells do not require watering within a 12-month interval. In fact, battery manufacturers now recommend watering intervals of 2 to 3 years for some new batteries. b. The maximum maintenance interval to verify that unmonitored communications systems are functional should be changed from 3 calendar months to 12 calendar months. FPL’s operating experience has shown that power line carrier (PLC) failures are primarily due to PLC protective devices (MOVs, gas tubes & spark gaps). Automated testing such as PLC check-back schemes cannot test for failed PLC protective devices. We believe a 12 calendar month functional test is sufficient because of FPL’s operating experience. FPL’s operating experience has shown that power line carrier (PLC) failures are primarily due to PLC protective devices (MOVs, gas tubes & spark gaps). c. We believe the data retention requirements for R2 and R3 should be documentation for the two most recent maintenance activities. d. Regarding Maintenance Correctable Issue (page2) where it states: “.such that it cannot be restored to functional order during performance of the initial on-site activity”. This terminology is vague: Particularly “initial on-site activity”. Not sure what “functional order” means? The suggestion is to change to “..such that the deficiency cannot be restored to meet applicable acceptance criteria during the performance of the scheduled maintenance activity”. e. Regarding Maintenance Correctable Issue (page 2) and R4 on Page 5, the suggestion is an entirely new “Maintenance Correctable” definition especially: “Therefore this issue requires followup corrective action”.

Organization	Yes or No	Question 5 Comment
		Regarding this new definition: Why is it here? Is its purpose to ask us to do something with these issues if we discover them? Do issues identified as "Maint. Correctable" need to be tracked and reported in some manner? The referenced term "Maint. Correctable" is only used in PRC-005-2 in R4 (page 5). The suggestion is to provide clarification. Is this maintenance correctable terminology implying that NERC PRC005-2 is opening up a new requirement for tracking and reporting resolution of "Maint Correctable" issues? The suggestion is to change to: This issue includes any activity requiring further follow-up corrective action to restore operability outside of the applicable maint activity f. Regarding Countable Event (Page 3), the suggestion is an entirely new "Countable Event" definition. Why is this new term and definition "countable event" included in PRC-005-2 ? Note: In the PRC005-2 text "countable event" is actually only referred to in PRC-005-2 in Attachment A under "Performance Based Programs" (not referred to in time based programs section). The recommendation is that the PRC-005-2 version explicitly clarify the definition of â "countable event" to clearly indicate that this term is applicable ONLY to "Performance Based Programs". g. Regarding Countable Event (page 3), where the text says "Any failure of a component which requires repair or replacement, any condition discovered during the verification activities in Tables 1-1/1-5 which requires corrective action..", in the definition for "countable event" what does "corrective action" mean? PRC005-2 is unclear. Does the term "countable event" have any ties to"Maint Correctable" issues. The suggestion is to Consider changing wording from "corrective action" to "which requires > 7 days to correct" and clarify whether or not "countable event" has any correlation to "Maint Correctable" events as discussed on page 2 and in R4? If so please provide language clarifying this correlation.

Response: Thank you for your comments.

a. This activity is primarily inspection-related, and addresses an inspection of electrolyte levels, dc grounds, and station dc supply voltages. Good practice is that entities will conduct a visual inspection of the overall battery condition during these activities, although the Standard does not require it. Also, please note that, while some batteries may reliably go longer between "watering", this activity is to detect gross failures, rather than specifically to address "watering". Please see Section 15.4 of the Supplementary Reference Document for further discussion.

b. A relay communications channel and equipment provide logic for a pilot protective relay system to operate correctly to clear faults instantaneously. Channel failure would cause the protective system to not operate or to operate incorrectly. An unmonitored channel failure will decrease reliability of that protective system until its failure is discovered. One year is too long to risk BES protective systems out of service. The three month interval is devised to maintain BES system reliability. If an entity's experience suggests that longer intervals are appropriate, they may employ performance-based maintenance per R2 and Attachment A. The definition of maintenance correctable issue has been revised to be clearer.

c. From SDT members' experiences, it is clear that auditors will generally wish to monitor compliance all the way back to the previous audit. Please see

Organization	Yes or No	Question 5 Comment
Compliance Application Notice CAN-008 for a discussion about pre-2007 data. d. The definition has been modified in consideration of your comment. Maintenance Correctable Issue – Failure of a component to operate within design parameters such that the deficiency cannot be corrected during the performance of the maintenance activity. Therefore this issue requires follow-up corrective action. e. Yes – the entity is expected to do something in response to an identified Maintenance Correctable Issue, but it is left to the entity to determine the best method for them to track the initiation of resolution of Maintenance Correctable issues. The definition of maintenance correctable issue has been revised to be clearer.. Please refer to M3 for some sample types of evidence. f. Countable events are used only within Attachment A. g. "Countable Event" applies only to performance-based maintenance, and is used solely to determine and evaluate the PBM maintenance intervals. A countable event may (or may not) be a maintenance correctable issue, depending on whether the deficiency is corrected while performing the maintenance activity or requires additional follow-up.		
U.S. Bureau of Reclamation (5)	Ballot Comment - Affirmative	The application of the PSMP should be explicitly defined in the standard. Currently the PSMP is required to protect rather than a PSMP to identify the components defined by the standard. The language should be altered to ensure the PSMP is developed for the component types specified in the standard. The following language should be considered: "Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2".
Response: Thank you for your comments. R1 has been modified as you suggest.		
NIPSCO		1. The present PRC-005 standard is 2 pages while the proposed PRC-005-2 is 22 pages, with an implementation plan of 4 pages and a supplemental document of 87 pages. The review process appears to be somewhat daunting especially considering that NERC is trying to simply things with such concepts as the "traffic ticket" approach. 2. In R3 we're not sure if there is a time requirement regarding the completion of the resolution process. We like the use of "calendar year" in requirements which should provide flexibility in getting the work completed. 3. Another comment for our response concerns Table 1-2, Communications Systems (page 11):The first maintenance interval is 3 calendar months. Does this mean the same as 1 calendar quarter?1. Example for 3 calendar months: Maintenance performed on 1/4/11. Next maint due by 4/30/11. Maintenance performed on 4/12/11. Next maint due by 7/31/11. Maintenance performed on 7/30/11. Next maint due by

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>10/31/11. This would yield 3 inspections for 2011. Maintenance performed on 10/12/11. Next maint due by 1/31/12.2. Example for 1 calendar quarter: Maintenance performed on 1/4/11. Next maint due by 6/30/11. This would yield 4 inspections for 2011 (1 per quarter).</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

1. The SDT has established maximum allowable intervals in accordance with FERC Order 693. Additionally, the SDT has addressed many of the common program-related causes of observed violations, and has provided the Supplementary Reference and FAQ to assist entities in implementing their program. The “traffic ticket” approach is focused on how the compliance monitor will assess violations, and has no bearing on the Standard itself.

2. The SDT has considered that, while some maintenance correctable issues may be completed very quickly, others may take an extended period (perhaps even several years) to complete effectively, during which time the degraded system must be reported and reflected within the operation of the BES in accordance with other standards. The SDT is concerned that the entity will not be able to record the maintenance activity as “complete” during the scheduled interval for these more extended activities to “correct”; therefore, the SDT has opted to require only that the entity initiate correction of maintenance correctable issues and rely on the operating focus on the degraded system to ensure that they are completed.

3. The intervals, “3 calendar months” and “once per calendar quarter” are not synonymous. “Once per calendar quarter” would effectively permit entities to have six months (less two days) between successive activities, while a “3 calendar month” interval limits an entity to four months (less two days) between activities. See Section 7.1 of the “PRC-005-2 Protection System Maintenance Supplementary Reference & FAQ” for a discussion about “calendar month” Basically every “3 Calendar Months” means to add 3 months from the last time the activity was performed.</td></tr>
<tr><td>Tenaska, Inc. (5)</td><td>Ballot Comment - Negative</td><td>1. The biggest concern we have with the proposed standard is the inclusion of 4.2.5.4. As written it is not clear, but more importantly it is overly broad and provides little, if any, increase to reliability. It needs to be deleted.

2. In Section 4.2, five types of protection systems are identified as being applicable, but the language of Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). We believe the intent is to have a PSMP for all Protection Systems identified in Section 4.2 and that the language of Requirement 1 may cause confusion or be misleading. We suggest changing the language of Requirement 1 from:

• Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to:

• Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection</td></tr>
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Organization	Yes or No	Question 5 Comment
		System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2.
Response: Thank you for your comments. 1. The 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. 2. R1 of the standard has been modified as you suggest.		
Seattle City Light (1) (3) (4)	Ballot Comment - Negative	Seattle City Light (SCL) commends the Standard Drafting Team (SDT) for the many improvements in the latest draft of proposed standard PRC-005-2. The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. Each draft has been better than that preceding, and the supporting material is very helpful in understanding the impact and implementation of the proposed Standard. However, SCL votes NO for this draft because of 1) the inclusion and treatment of electromechanical lockout relays within the scope of draft Standard and 2) 2) confusion about language between section 4.2 and Requirement 1. 1. Regarding electromechanical lockout relays, SCL is highly concerned about the reliability risks and logistical difficulties associated with meeting the requirements proposed for these relays. Lockout relays operate rarely and are known for reliable service. For many such relays, the proposed maintenance would require clearance of entire bus sections or even multiple bus sections (such as for a bus differential lockout relay). In SCL's opinion, the reliability risks posed by such switching and outages to the Bulk Electric System outweigh the reliability benefits of including lockout relays in the scope of PRC-005-2. If the SDT deems it necessary to include electromechanical lockout relays within PRC-005-2, SCL recommends that a difference be made between the maintenance activities specified for monitored and unmonitored types. The draft Standard describes the requirements for "electromechanical lockout and/or tripping auxiliary devices" in Table 1-5 (p.19) and assigns a 6-year maximum maintenance interval, the same as for other unmonitored relays. Modern electromechanical lockout relays may be specified with a built-in self-monitoring trip-coil alarm. SCL believes the maintenance requirements for electromechanical lockout relays with such an alarm should be similar to those for other alarmed or monitored relays. As such we recommend that a new entry be added to Table 1-5 for monitored electromechanical lockout relays, as follows:

Organization	Yes or No	Question 5 Comment
		• Component Attributes: Electromechanical lockout and/or tripping auxiliary devices which are directly in a trip path from the protective relay to the interrupting device trip coil AND include built-in self-monitoring trip-coil alarm • Maximum Maintenance Interval: 12 calendar years • Maintenance Activities: Verify electrical operation of electromechanical trip and auxiliary devices. Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. 2. We also would like to comment regarding confusion over language in section 4.2.This section identifies five types of Facilities that the standard is applicable to, whereas Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). As such, it is not clear if PRC-005-2 applies to five Facilities or to certain Protection Systems. SCL believes the intent is to have a PSMP for all Protection Systems identified in "Part A, Section 4.2 - Facilities" and that the language of Requirement 1 may cause confusion or be misleading. We suggest changing the language of Requirement 1 from: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Facilities identified in Part A, Section 4.2.
Response: Thank you for your comments. 1. The SDT believes that performing these maintenance activities will benefit the reliability of the BES. The SDT believes that electromechanical devices having moving parts share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-Based maintenance is an option to increase the intervals if the performance of these devices supports those intervals. 2. R1 has been modified as you suggest.		
Seattle City Light (5) (6)	Ballot Comment - Negative	Seattle City Light (SCL) commends the Standard Drafting Team (SDT) for the many improvements in the latest draft of proposed standard PRC-005-2. The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. Each draft has been better than that preceding, and the supporting material is very helpful in understanding the impact and implementation of the proposed Standard. However, SCL votes NO for this draft because of

Organization	Yes or No	Question 5 Comment
		1) the inclusion and treatment of electromechanical lockout relays within the scope of draft Standard and 2) confusion about language between section 4.2 and Requirement 1. 1. Regarding electromechanical lockout relays, SCL is highly concerned about the reliability risks and logistical difficulties associated with meeting the requirements proposed for these relays. Lockout relays operate rarely and are known for reliable service. For many such relays, the proposed maintenance would require clearance of entire bus sections or even multiple bus sections (such as for a bus differential lockout relay). In SCL's opinion, the reliability risks posed by such switching and outages to the Bulk Electric System outweigh the reliability benefits of including lockout relays in the scope of PRC-005-2. If the SDT deems it necessary to include electromechanical lockout relays within PRC-005-2, SCL recommends that a difference be made between the maintenance activities specified for monitored and unmonitored types. The draft Standard describes the requirements for "electromechanical lockout and/or tripping auxiliary devices" in Table 1-5 (p.19) and assigns a 6-year maximum maintenance interval, the same as for other unmonitored relays. Modern electromechanical lockout relays may be specified with a built-in self-monitoring trip-coil alarm. SCL believes the maintenance requirements for electromechanical lockout relays with such an alarm should be similar to those for other alarmed or monitored relays. As such we recommend that a new entry be added to Table 1-5 for monitored electromechanical lockout relays, as follows: • Component Attributes: Electromechanical lockout and/or tripping auxiliary devices which are directly in a trip path from the protective relay to the interrupting device trip coil AND include built-in self-monitoring trip-coil alarm o Maximum Maintenance Interval: 12 calendar years • Maintenance Activities: Verify electrical operation of electromechanical trip and auxiliary devices. Verify that the alarm path conveys alarm signals to a location where corrective action can be initiated. 2. Regarding confusion over language, section 4.2 section identifies five types of Facilities that the standard is applicable to, whereas Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). As such, it is not clear if PRC-005-2 applies to five Facilities or to certain Protection Systems. SCL believes the intent is to have a PSMP for all Protection Systems identified in "Part A, Section 4.2 - Facilities" and that the language of Requirement 1 may cause confusion or be misleading. We suggest changing the language of Requirement 1 from: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection

Organization	Yes or No	Question 5 Comment
		System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Facilities identified in Part A, Section 4.2.
Response: Thank you for your comments. 1. The SDT believes that performing these maintenance activities will benefit the reliability of the BES. The SDT believes that electromechanical devices having moving parts share performance attributes (and failure modes) with electromechanical relays and need to be tested at similar intervals. Performance-Based maintenance is an option to increase the intervals if the performance of these devices supports those intervals. 2. R1 has been modified as you suggest.		
Colorado Springs Utilities (1)	Ballot Comment - Negative	The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. However, section 4.2 identifies five types of protection systems that the standard is applicable to, but the language of Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). We believe the intent is to have a PSMP for all Protection Systems identified in Section 4.2 and that the language of Requirement 1 may cause confusion or be misleading. We suggest changing the language of Requirement 1 from: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2. Even with this change, the standard is still vague given the fact that there is no clear definition of "BES" or "Protective relay".
Response: Thank you for your comments. R1 has been modified as you suggest.		
Western Electricity Coordinating Council (10)	Ballot Comment - Affirmative	The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. However, section 4.2 identifies five types of protection systems that the standard is applicable to, but the language of Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). We believe the intent is to have a PSMP for all Protection Systems identified in Section 4.2 and that the language of Requirement 1 may cause confusion or be misleading. To address the potential for confusion we

Organization	Yes or No	Question 5 Comment
		suggest changing the language of Requirement 1 from: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2.
Western Electricity Coordinating Council		The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. However, section 4.2 identifies five types of protection systems that the standard is applicable to, but the language of Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). We believe the intent is to have a PSMP for all Protection Systems identified in Section 4.2 and that the language of Requirement 1 may cause confusion or be misleading. We suggest changing the language of Requirement 1 from: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2.
Response: Thank you for your comments. R1 has been modified as you suggest.		
California Energy Commission (9) Entegra Power Group, LLC (5)Idaho Power Company (1) NorthWestern Energy (1) Platte River Power Authority (1)	Ballot Comment – Affirmative (except for PUD of Grant County - Negative	The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. However, section 4.2 identifies five types of protection systems that the standard is applicable to, but the language of Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). We believe the intent is to have a PSMP for all Protection Systems identified in Section 4.2 and that the language of Requirement 1 may cause confusion or be misleading. We suggest changing the language of Requirement 1 from: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to:

Organization	Yes or No	Question 5 Comment
(3) (6) Public Utility District No. 1 of Douglas County (4) Public Utility District No. 2 of Grant County (3) Utah Public Service Commission (9)		• Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2.
Response: Thank you for your comments. The Standard has been modified as you suggest.		
Tucson Electric Power Co. (1)	Ballot Comment - Negative	The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. However, section 4.2 identifies five types of protection systems that the standard is applicable to, but the language of Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). I believe the intent is to have a PSMP for all Protection Systems identified in Section 4.2 and that the language of Requirement 1 may cause confusion or be misleading. Suggest changing the language of Requirement 1 to: • Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2.
Response: Thank you for your comments. The Standard has been modified as you suggest.		
Ingleside Cogeneration LP		The removal of R1.5 and R7 which required Protection System owners to identify and verify calibration tolerances or equivalent parameters upon conclusion of a maintenance activity was fundamental to Ingleside Cogeneration's yes vote. The amount of ambiguity introduced by the requirements and associated documentation did not serve to improve BES reliability in our view.
Response: Thank you for your comments.		
Transmission Access Policy		The scope of the equipment to which the draft standard applies is over-broad.

Organization	Yes or No	Question 5 Comment
Study Group		Specifically, PRC-005-2 should not apply to non-relay equipment for UFLS and UVLS systems. Subjecting UFLS and UVLS batteries, instrument transformers, DC control circuitry, and communications to the requirements of PRC-005-2 would drastically increase the scope of equipment covered by the standard, with no corresponding benefit to reliability, for the following reasons. In contrast to transmission and generation protection systems and SPSs, for which there are typically two protection systems per facility and therefore per fault, UFLS and UVLS deal with widespread events. For any under-voltage or under-frequency event, there are literally hundreds of UFLS/UVLS relays to respond. It is therefore far less critical if one UFLS or UVLS relay fails to operate properly. Furthermore, transmission is typically not radial (in fact, radials to load are excluded from the BES). But distribution circuits, where UFLS and UVLS systems are located, are usually radial. Testing some of the non-relay equipment to which the draft standard applies would require blacking out the customers served by that radial. In other words, the draft standard would require entities to definitely cause blackouts in an attempt to prevent very unlikely potential blackouts. This is plainly not justified from a harm/benefit perspective. Finally, many of the types of non-relay equipment to which the standard would apply are in effect tested by faults. Specifically, faults happen on distribution circuits (where UFLS and UVLS systems are located) more frequently than on transmission circuits, due to such things as animal contacts and car accidents. Any such fault is in fact a test of the all the equipment that is involved in clearing the fault. There is no need to require separate tests of that equipment, any more than we would require tests of a phone line that is used on an everyday basis; you already know that the phone works.
Response: Thank you for your comments. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition.		
Illinois Municipal Electric Agency		The scope of the equipment to which the draft standard applies is still overly broad. Specifically, PRC-005-2 should not apply to non-relay equipment for UFLS and UVLS systems. Subjecting UFLS and UVLS batteries, instrument transformers, DC control circuitry, and communications to the requirements of PRC-005-2 would drastically increase the scope of equipment covered by the standard, with no corresponding benefit to reliability of the BES. This comment/recommendation is provided to address the resource and customer service interests of a TO and/or DP systems serving distribution load. Illinois Municipal Electric Agency supports comments submitted by the Transmission Access Policy Study Group.
Response: Thank you for your comments. Section 202 of the NERC Rules of Procedure define “Reliability standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition.		
ISO/RTO Standards Review		The SRC disagrees with the change to the term under 4.2.1. “Protection Systems designed to provide protection for BES elements.” We support keeping the previous version’s wording of 4.2.1. “Protection

Organization	Yes or No	Question 5 Comment
Committee		Systems applied on, or designed to provide protection for the BES." The revised wording expands the fundamental purpose of the NERC PRC-005 standard from being focused on ensuring relays intended to protect the reliability of the BES are maintained to a standard whose intent is to ensure all BES facilities have relay maintenance programs. Although we do not disagree with maintaining all relays, regardless of what their intended purposes are, it should not be the purpose of a NERC standard to police all protection schemes beyond those needed for interconnected reliability. There are numerous protective relays employed on facilities interconnected to the BES but their purpose may be for operating preference or service/equipment quality purposes such as reclosing schemes and transformer sudden pressure relays. We believe the NERC PRC-005 standard should be focused on maintenance of those protective relays which are needed to ensure that the loss of a single element does not cause cascading effects on the bulk power system.
Response: Thank you for your comments. Clause 4.2.1 has been modified to improve consistency with the Interpretation that has become part of PRC-005-1a.		
Duke Energy		The Standard Drafting Team has done an outstanding job on this standard. We are voting "Affirmative" but note that implementation questions remain, particularly with regards to classifying component attributes as "monitored," "unmonitored," "internal self diagnosis," "alarming," "alarming for excessive error" and "alarming for excessive performance degradation". The sheer size of the population of protective relays, communications systems, voltage and current sensing devices, batteries, and dc supply components means that the size of the effort required to categorize each individual component could drive us to test and maintain on the more frequent unmonitored time intervals, simply because of the difficulty in assembling "monitored" compliance documentation.
Response: Thank you for your comments. The opportunity to use "monitoring" to extend the intervals and reduce the activities, as well as the opportunity to use performance-based maintenance, is provided for those entities who wish to apply the administrative resources in order to minimize the field maintenance. If entities choose not to use those opportunities, the SDT believes that the un-monitored intervals and activities will establish an effective PSMP.		
Pepco Holdings Inc		There were numerous comments submitted for each of the previous drafts indicating that the 3 month interval for verifying unmonitored communication systems was much too short. The SDT declined to change the interval and in their response stated: "The 3 month intervals are for unmonitored equipment and are based on experience of the relaying industry represented by the SDT, the SPCTF and review of IEEE PSRC work. Relay communications using power line carrier or leased audio tone circuits are prone to channel failures and are proven to be less reliable than protective relays." Statistics on the causes of BES protective system misoperations, however, do not support this assertion. The PJM Relay Subcommittee has been tracking 230kV and above protective system misoperations on the PJM system for many years. For the six year period from 2002 to 2007, the number of protective system misoperations due to communication system problems was lower (and in many cases significantly lower) than those caused by defective relays, in every year but one. Similarly, RFC has conducted an analysis of BES protection system misoperations for 2008

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 5 Comment</th></tr>
<tr><td></td><td></td><td>and 2009, and found the number of misoperations caused by communication system problems to be in line with the number attributed to relay related problems. If unmonitored protective relays have a 6 year maximum maintenance/inspection interval, it does not seem reasonable to require the associated communication system to be inspected 24 times more frequently, particularly when relay failures are statistically more likely to cause protective system misoperations. As such, a 12 or 18 calendar month interval for inspection of unmonitored communication systems would seem to be more appropriate. FAQ II 6 B states that the concept should be that the entity verify that the communication equipment...is operable through a cursory inspection and site visit. However, unlike FSK schemes where channel integrity can easily be verified by the presence of a guard signal, ON-OFF carrier schemes would require a check-back or loop-back test be initiated to verify channel integrity. If the carrier set was not equipped with this feature, verification would require personnel to be dispatched to each terminal to perform these manual checks. The SDT responded that they still felt the 3 month interval as stated in the standard was appropriate. PHI respectfully requests that the SDT reconsider this issue and also cite what "specific statistical data" they used to validate that unmonitored communication systems are 24 times more prone to failure than unmonitored protective relays.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

The SDT believes that relay communications channels are more susceptible to failure from an outside influence than a protective relay. Leased circuits from communications providers and carrier channels are highly exposed to lightning, automobiles, backhoes, etc. We believe the existing statistics from PJM and RFC on relay communications system based misoperation causes is due to the present practice of periodic channel verifications being performed. Many utilities presently use channel monitoring and carrier checkbacks to ensure reliable operation.</td></tr>
<tr><td>Liberty Electric Power LLC (5)</td><td>Ballot Comment - Negative</td><td>While the SDT has done a very good job at responding to the most objectionable parts of the previous version, there are still a number of issues which makes the standard problematic.

1. The standard introduces the term "initiate resolution". This is an interpretable term, and has the potential for an auditor and an entity to disagree on an action. Would issuing a work order be considered "initiating resolution"? What if the WO had a completion date many years into the future? I would suggest adding the term to the list of definitions which will remain with the standard, and defining it as "performing any task associated with conducting maintenance activities, including but not limited to issuing purchase orders, soliciting bids, scheduling tasks, issuing work requests, and performing studies".

2. Some clarity is needed to differentiate system connected and generator connected station service transformers. A statement that a station service transformer connected radially to the generator bus is considered a system connected transformer if the transformer cannot be used for service unless connected to the BES.

3. The "bookends" issue, brought up in the prior round of comments, still exists. Although the SDT rightly notes a CAN has been issued regarding bookends, the CAN covers the documentation for system</td></tr>
</table>

Organization	Yes or No	Question 5 Comment
		components that entities were required to self-certify to on June 18, 2007. PRC-005-2 adds additional components to the protection system scheme which were not part of that certification, and has the potential to put entities into violation space due to a lack of records for those components. 4. The SDT should add to M3 a statement that entities may demonstrate compliance with the standard by demonstrating that required activities took place twice within the maximum maintenance interval -starting from the effective date of the standard - for all components not listed in PRC-005-1.
Response: Thank you for your comments. 1. The SDT believes that issuing a work order would satisfy this requirement. M3 presents several examples of relevant evidence. The SDT has considered that, while some maintenance correctable issues may be completed very quickly, others may take an extended period (perhaps even several years) to complete effectively, during which time the degraded system must be reported and reflected within the operation of the BES in accordance with other standards. The SDT is concerned that the entity will not be able to record the maintenance activity as "complete" during the scheduled interval for these more extended activities to "correct the maintenance correctable issue"; therefore, the SDT has opted to require only that the entity initiate correction of maintenance correctable issues and rely on the operating focus on the degraded system to ensure that they are completed. 2. The 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. System connected station service transformers were removed from the Applicability in a previous draft. 3. The Implementation Plan specifies that entities may implement PRC-005-2 incrementally throughout the intervals specified, and that they shall follow their existing program for components not yet implemented. The SDT believes that the "bookends" issue to which you refer is therefore addressed. 4. The Standard requires that activities only take place once within the established interval.		
SPP reliability standard development Team		Would like more clarification in table 1-5 to address verification tests on different circuits. Is this an end to end test or partial test can you test one part of the circuit one way and another a different way? Should table 1-5 read Complete a terminal test of unmonitored circuitry?
Response: Thank you for your comments. The SDT does not believe that the suggested text adds clarity to the standard. Please see Section 15.3 of the Supplementary Reference Document for additional discussion.		
Lakeland Electric (1)	Ballot Comment - Negative	The new PRC-005-2 includes non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability. While Lakeland Electric agrees wholeheartedly with the inclusion of non-relay components for BES Protection Systems. It is critical that BES Protection Systems work and clear the fault (e.g., on > 100 kV Facilities).

Organization	Yes or No	Question 5 Comment
		However, UFLS and UVLS are quite different. For an event requiring UFLS and UVLS operation, there are many, e.g., hundreds and possibly thousands of relays, that operate to shed load automatically and if a small percentage of those do not operate as expected, the impact is minimal. So, it is not important for BES reliability to include non-relay components of UFLS and UVLS in the PRC-005-2 standard.
Response: Thank you for your comments. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition.		
City of Bartow, Florida (3)	Ballot Comment - Negative	There is an unnecessary expansion of the scope of equipment covered by this standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The new PRC-005-2 includes these non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability. We agree wholeheartedly with the inclusion of non-relay components for BES Protection Systems. It is critical that BES Protection Systems work and clear the fault (e.g., on > 100 kV Facilities). However, UFLS and UVLS are quite different. For an event requiring UFLS and UVLS operation, there are many, e.g., hundreds and possibly thousands of relays, that operate to shed load automatically and if a small percentage of those do not operate as expected, the impact is minimal. So, it is not important for BES reliability to include non-relay components of UFLS and UVLS in the PRC-005-2 standard. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. For instance, testing trip coils of a distribution breakers will likely results in service interruption to customers on that distribution circuit in order to test the breaker or to perform break-before-make switching on the distribution system often required to manage maximum available fault current on the distribution system for worker safety, etc.. Hence, the standard would be sacrificing customer service quality for an infinitesimal increase in BES reliability. In addition, non-relay protection components operate much more frequently on distribution circuits than on transmission Facilities due to more frequent failures due to trees, animals, lightning, traffic accidents, etc., and have much less of a need for testing since they are operationally tested.
Response: Thank you for your comments. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition.		
Lakeland Electric (6)	Ballot Comment -	Unnecessary expansion of the scope of equipment covered by this standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and

Organization	Yes or No	Question 5 Comment
	Negative	PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The new PRC-005-2 includes these non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability.
Response: Thank you for your comments. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition.		
Beaches Energy Services (1)	Ballot Comment - Negative	We believe that there is an unnecessary expansion of the scope of equipment covered by this standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The new PRC-005-2 includes these non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability. We agree wholeheartedly with the inclusion of non-relay components for BES Protection Systems. It is critical that BES Protection Systems work and clear the fault (e.g., on > 100 kV Facilities). However, UFLS and UVLS are quite different. For an event requiring UFLS and UVLS operation, there are many, e.g., hundreds and possibly thousands of relays, that operate to shed load automatically and if a small percentage of those do not operate as expected, the impact is minimal. So, it is not important for BES reliability to include non-relay components of UFLS and UVLS in the PRC-005-2 standard. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. For instance, testing trip coils of distribution breakers will likely result in service interruption to customers on that distribution circuit in order to test the breaker or to perform break-before-make switching on the distribution system often required to manage maximum available fault current on the distribution system for worker safety, etc.. Hence, the standard would be sacrificing customer service quality for an infinitesimal increase in BES reliability. In addition, non-relay protection components operate much more frequently on distribution circuits than on Transmission Facilities due to more frequent failures due to trees, animals, lightning, traffic accidents, etc., and have much less of a need for testing since they are operationally tested.
Response: Thank you for your comments. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition.		
Keys Energy Services (1)	Ballot Comment -	1. KEYS believes that there is an unnecessary expansion of the scope of equipment covered by this standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument

Organization	Yes or No	Question 5 Comment
	Negative	transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The new PRC-005-2 includes these non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability. KEYS agrees wholeheartedly with the inclusion of non-relay components for BES Protection Systems. It is critical that BES Protection Systems work and clear the fault (e.g., on > 100 kV Facilities). However, UFLS and UVLS are quite different. For an event requiring UFLS and UVLS operation, there are many, e.g., hundreds and possibly thousands of relays, that operate to shed load automatically and if a small percentage of those do not operate as expected, the impact is minimal. So, it is not important for BES reliability to include non-relay components of UFLS and UVLS in the PRC-005-2 standard. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. For instance, testing trip coils of a distribution breakers will likely results in service interruption to customers on that distribution circuit in order to test the breaker or to perform break-before-make switching on the distribution system often required to manage maximum available fault current on the distribution system for worker safety, etc.. Hence, the standard would be sacrificing customer service quality for an infinitesimal increase in BES reliability. In addition, non-relay protection components operate much more frequently on distribution circuits than on transmission Facilities due to more frequent failures due to trees, animals, lightning, traffic accidents, etc., and have much less of a need for testing since they are operationally tested. 2. As another comment, station service transformers are not BES Elements and should not be part of the Applicability - they are radial serving only load.
Response: Thank you for your comments. 1. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition. 2. The 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. System connected station service transformers were removed from the Applicability in a previous draft.		
Lakeland Electric (3)	Ballot Comment - Negative	1. LAK believes that there is an unnecessary expansion of the scope of equipment covered by this standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included

Organization	Yes or No	Question 5 Comment
		in those standards. The new PRC-005-2 includes these non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability. LAK agrees wholeheartedly with the inclusion of non-relay components for BES Protection Systems. It is critical that BES Protection Systems work and clear the fault (e.g., on > 100 kV Facilities). However, UFLS and UVLS are quite different. For an event requiring UFLS and UVLS operation, there are many, e.g., hundreds and possibly thousands of relays, that operate to shed load automatically and if a small percentage of those do not operate as expected, the impact is minimal. So, it is not important for BES reliability to include non-relay components of UFLS and UVLS in the PRC-005-2 standard. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. For instance, testing trip coils of a distribution breakers will likely results in service interruption to customers on that distribution circuit in order to test the breaker or to perform break-before-make switching on the distribution system often required to manage maximum available fault current on the distribution system for worker safety, etc.. Hence, the standard would be sacrificing customer service quality for an infinitesimal increase in BES reliability. In addition, non-relay protection components operate much more frequently on distribution circuits than on transmission Facilities due to more frequent failures due to trees, animals, lightning, traffic accidents, etc., and have much less of a need for testing since they are operationally tested. 2. As another comment, station service transformers are not BES Elements and should not be part of the Applicability - they are radial serving only load.
Response: Thank you for your comments. 1. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition. 2. The 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. System connected station service transformers were removed from the Applicability in a previous draft.		
City of Green Cove Springs (3)	Ballot Comment - Negative	1. GCS believes that there is an unnecessary expansion of the scope of equipment covered by this standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The new PRC-005-2 includes these non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment;

Organization	Yes or No	Question 5 Comment
		hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability. GCS agrees wholeheartedly with the inclusion of non-relay components for BES Protection Systems. It is critical that BES Protection Systems work and clear the fault (e.g., on > 100 kV Facilities). However, UFLS and UVLS are quite different. For an event requiring UFLS and UVLS operation, there are many, e.g., hundreds and possibly thousands of relays, that operate to shed load automatically and if a small percentage of those do not operate as expected, the impact is minimal. So, it is not important for BES reliability to include non-relay components of UFLS and UVLS in the PRC-005-2 standard. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. For instance, testing trip coils of a distribution breakers will likely results in service interruption to customers on that distribution circuit in order to test the breaker or to perform break-before-make switching on the distribution system often required to manage maximum available fault current on the distribution system for worker safety, etc.. Hence, the standard would be sacrificing customer service quality for an infinitesimal increase in BES reliability. In addition, non-relay protection components operate much more frequently on distribution circuits than on transmission Facilities due to more frequent failures due to trees, animals, lightning, traffic accidents, etc., and have much less of a need for testing since they are operationally tested. 2. As another comment, station service transformers are not BES Elements and should not be part of the Applicability - they are radial serving only load.
Response: Thank you for your comments. 1. Section 202 of the NERC Rules of Procedure defines "Reliability Standard" as "a requirement to provide for reliable operation of the bulk power system …" The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition. 2. The 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. System connected station service transformers were removed from the Applicability in a previous draft.		
Gainesville Regional Utilities (1)	Ballot Comment - Negative	GRU (GVL) agrees with the following comments provided by the FMPA: 1. FMPA believes that there is an unnecessary expansion of the scope of equipment covered by this standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The new PRC-005-2 includes these non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, these non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system

Organization	Yes or No	Question 5 Comment
		components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the standard with negligible benefit to BES reliability. FMPA agrees wholeheartedly with the inclusion of non-relay components for BES Protection Systems. It is critical that BES Protection Systems work and clear the fault (e.g., on > 100 kV Facilities). However, UFLS and UVLS are quite different. For an event requiring UFLS and UVLS operation, there are many, e.g., hundreds and possibly thousands of relays, that operate to shed load automatically and if a small percentage of those do not operate as expected, the impact is minimal. So, it is not important for BES reliability to include non-relay components of UFLS and UVLS in the PRC-005-2 standard. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. For instance, testing trip coils of a distribution breakers will likely results in service interruption to customers on that distribution circuit in order to test the breaker or to perform break-before-make switching on the distribution system often required to manage maximum available fault current on the distribution system for worker safety, etc.. Hence, the standard would be sacrificing customer service quality for an infinitesimal increase in BES reliability. In addition, non-relay protection components operate much more frequently on distribution circuits than on transmission Facilities due to more frequent failures due to trees, animals, lightning, traffic accidents, etc., and have much less of a need for testing since they are operationally tested. 2. As another comment, station service transformers are not BES Elements and should not be part of the Applicability - they are radial serving only load.
Response: Thank you for your comments. 1. Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition. 2. The 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. System connected station service transformers were removed from the Applicability in a previous draft.		
Alliant Energy		1. If PRC-005-2 is going to incorporate PRC-008 (UFLS) and PRC-011 (UVLS) the Purpose needs to be revised to include Distribution Protection Systems designed to protect the BES. 2. We do not believe a distribution relaying system, designed to protect the distribution assets, that may open a transmission element (ie; breaker failure) should be considered part of the BES Protection System. R1 should add the following sentence “Distribution Protection Systems intended solely for the protection of distribution assets are not included as a BES Protection System, even if they may open a BES Element.” 3. Table 1-5 (Component Type - Control Circuitry) Item 4 “Unmonitored control circuitry associated with protective functions” require a 12 calendar year maximum maintenance interval. We believe UFLS and

Organization	Yes or No	Question 5 Comment
		UVLS control circuitry should be exempted from this requirement. It would take multiple failures to have any impact, and the impact on the BES would be minimal.
Response: Thank you for your comments. 1. There is no distinction in the purpose between "Distribution Protection Systems" and "Transmission Protection Systems". The SDT believes that the Applicability appropriately describes both the entities and the facilities. 2. The SDT modified Applicability 4.2.1 for better consistency with the interpretation that is reflected in PRC-005-1a, and believes that this change may address your concern. 3. The Table 1-5 activities for UFLS/UVLS are constrained to those activities that the SDT considers to be appropriate relative to the reliability impact of these applications. Please see Section 15.3 of the Supplemental Reference Document for additional discussion on this topic.		
Y-W Electric Association, Inc. (4)	Ballot Comment - Affirmative	Y-WEA thanks the SDT for its long, hard work on this standard and for its consideration of previous comments.
Response: Thank you for your comments.		
BGE		No comments.
PNGC Power		Thank you for the opportunity to comment on the draft Standard PRC-005-2 – Protection System Maintenance. 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

Organization	Yes or No	Question 5 Comment
		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 <u>not</u> 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

Organization	Yes or No	Question 5 Comment
		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 comments. The SDT has revised R1 to refer to Applicability 4.2. The SDT believes that your comments are otherwise already reflected in the Standard, and that no further changes are necessary. The Standard currently addresses maintenance of all Protection Systems that are applied on or to protect BES elements, as well as maintenance of UFLS installed for the BES per PRC-007, UVLS installed on or for the BES per PRC-010, and Special Protection Systems installed on or for the BES per PRC-012, PRC-013, PRC-014, and PRC-015. Therefore, the Standard is already constrained as you suggest. Additionally, Section 202 of the NERC Rules of Procedure defines “Reliability Standard” as “a requirement to provide for reliable operation of the bulk power system …” The requirements regarding maintenance of Protection Systems for UFLS and UVLS directly support this definition.		
ReliabilityFirst	Ballot Comment - Affirmative	ReliabilityFirst votes affirmative but offers the following suggestions/comments: 1. R3 should be split into two separate requirements since there are two distinct actions being requested (e.g. “…shall implement and follow its PSMP” is one requirement and “… shall initiate resolution of any identified maintenance correctable issues” is the second requirement. 2. There are a number of terms which are defined only for the use of the PRC-005-2 standard which will not be moved to the Glossary of Terms., and even though I completely agree with this concept, I believe this concept is not mentioned nor is it allowed per the NERC Standard Processes Manual.
Response: Thank you for your comments. 1. The SDT believes that the two activities are intertwined and should remain within a single requirement. 2. The SDT has been advised by NERC Standards staff that this is acceptable, and has adopted the methodology for doing so as suggested by staff.		