Consideration of Comments

Project 2007-17
Protection System Maintenance and Testing

The Project 2007-17 Protection System Maintenance and Testing Standard Drafting Team thanks all commenters who submitted comments on PRC-005-2. These documents were posted for a 30-day public comment period from February 28, 2012 through March 28, 2012. Stakeholders were asked to provide feedback on the standard and associated documents through a special electronic comment form. There were 56 sets of comments, including comments from approximately 118 different people from approximately 98 companies representing 9 of the 10 Industry Segments, as shown in the table on the following pages.

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

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President of Standards and Training, Herb Schrayshuen, at 404-446-2560 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

Summary Consideration of all Comments Received:

Definitions:

The SDT revised the "Inspect" element of the definition of Protection System Maintenance Program (PSMP) to: "Examine for signs of component failure, reduced performance or degradation."

The definition of the term 'Unresolved Maintenance Issue' has been enhanced for additional clarity. The definition now reads: "A deficiency identified during a maintenance activity that causes the component to not meet the intended performance, cannot be corrected during the maintenance interval, and requires follow-up corrective action."

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

The definition of Countable Event was modified to: "A failure of a Component requiring repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to product design errors, software errors, relay settings different from specified settings, Protection System Component configuration errors, or Protection System application errors are not included in Countable Events." This change was acknowledged in Attachment A.

Applicability:

The SDT revised Applicability Clause 4.2.5.4 to: "Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays."

Requirements:

A minor editorial change was made to Requirement R1 to remove the nested parentheticals.

Tables

In Table 1-2, the interval for the second portion of the first row of the table was changed from six years to 12 years, and extensive changes were made to the last row of the table.

Several activities within Table 1-4a, Table 1-4b, Table 1-4c, Table 1-4d, and Table 1-4f, relating to verification that the station battery can perform properly, were modified with the assistance of representatives of the IEEE Stationary Battery Committee.

Measures

Measure M5 has been revised to include: "…project schedules with completed milestones …"

VSLs

In the High VSL for R1, "entities'" was corrected to "entity's".

The VSLs for Requirement R2 were modified from "reduce Countable Events to less than 4%" to "reduce Countable Events to no more than 4%".

Supplementary Reference Document

Complementary changes were made to the Supplementary Reference Document corresponding to all changes to the standard.

Unresolved Minority Views:

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

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

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

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

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

- Several commenters suggested removal of Requirement R5, and others expressed concerns regarding Requirement R5 and Unresolved Maintenance Issues. The SDT explained its rationale for the requirement as drafted; and made a minor change to Unresolved Maintenance Issues, as detailed above.

NERC

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

1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Chantel Haswell	FPL Group, Inc.	NPCC	5
9.	David Kiguel	hydro One Networks Inc.	NPCC	1
10.	Michael R. Lombardi	Northeast Utilities	NPCC	1
11.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
12.	Bruce Metruck	New York Power Authority	NPCC	6
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

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

14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
17.	Brian Robinson	Utility Services	NPCC	8
18.	Saurabh Saksena	National Grid	NPCC	1
19.	Michael Schiavone	National Grid	NPCC	1
20.	Wayne Sipperly	New York Power Authority	NPCC	5
21.	Tina Teng	Independent Electricity System Operator	NPCC	2
22.	Donald Weaver	New Brunswick System Operator	NPCC	2
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	Jim Eckelkamp	Progress Energy										

No additional members listed.

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Kent Kujala	DTE Energy			X	X	X					

1.	Steven Kerkmaz		RFC	3, 4, 5
2.	David Szulczewski		RFC	3, 4, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	WILL SMITH	MRO NSRF	X		X		X	X				

1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL(NSP)	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	3, 5, 6, 1
12.	MARIE KNOX	MISO	MRO	2

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

13. LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14. SCOTT BOS	MPW	MRO	1, 3, 5, 6
15. TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16. MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17. THERESA ALLARD	MPC	MRO	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Kieth Morisette	Tacoma Public Utilities										

No additional members listed.

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6. Group	Jesus Sammy Alcaraz	Imperial Irrigation District (IID)	X		X	X	X	X				

1. Jose Landeros	IID	WECC	1, 3, 4, 5, 6
2. Epi Martinez	IID	WECC	1, 3, 4, 5, 6
3. Nando Gutierrez	IID	WECC	1, 3, 4, 5, 6

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

1. Michael Gildea	NERC Compliance Policy	RFC	5, 6
2. Michael Crowley	Electric Transmission	SERC	1, 3
3. Sean Iseminger	Fossil & Hydro	SERC	5
4. Chip Humphrey	Fossil & Hydro	MRO	5
5. Jeff Bailey	Nuclear		5
6. Connie Lowe	NERC Compliance Policy	SERC	5, 6
7. Mike Garton	NERC Compliance Policy	NPCC	5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8. Group	Don Jones	Texas Reliability Entity										X

1. Curtis Crews	Texas RE	ERCOT	10
2. David Penney	Texas RE	ERCOT	10

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9. Group	Jonathan Hayes	Southwest Power Pool Standards Development Team	X			X						

1. John Allen	City Utilities of Springfield	SPP	1, 4
2. Greg Froehling	Rayburn Electric	SPP	
3. Louis Guidry	CLECO	SPP	1, 3, 5
4. Jonathan Hayes	Southwest Power Pool	SPP	2
5. Robert Rhodes	Southwest Power Pool	SPP	2

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

6. Robert Hirchak	CLECO	SPP	1, 3, 5
7. Brandon Nugent	CLECO	SPP	1, 3, 5
8. Valerie Pinamonti	AEP	SPP	1, 3, 5
9. Mahmood Safi	OPPD	SPP	1, 3, 5

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

1. Rusty Hardison	Transmission O&M	SERC	NA
2. Pat Caldwell	Transmission O&M - Relay	SERC	NA
3. Paul Barnett	Transmission O&M - Substation	SERC	NA
4. Jerry Finley	Power Control Systems	SERC	NA
5. Frank Cuzzort	Nuclear Engineering	SERC	NA
6. Robert Brown	Nuclear Engineering	SERC	NA
7. Robert Mares	Hydro Engineering	SERC	NA
8. Annette Dudley	Hydro O&M	SERC	NA
9. John Henry Sullivan	Fossil Engineering	SERC	NA
10. David Thompson	Compliance	SERC	NA

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

1. Jim Kinney	FE	RFC	1
2. Brian Orians	FE	RFC	5
3. Rusty Loy	FE	RFC	5
4. Shawn Gehring	FE	RFC	1
5. Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
6. Bill Duge	FE	RFC	5
7. Chris Lassak	FE	RFC	5
8. Mike Ferncez	FE	RFC	1
9. Tim Sheerer	FE	RFC	1

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

1. Joe Jarvis	Blachly-Lane Electric Cooperative	WECC	3
2. Dave Markham	Central Electric Cooperative	WECC	3
3. Dave Hagen	Clearwater Power Cooperative	WECC	3

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

4.	Roman Gillen	Consumer's Power Inc.	WECC	1, 3
5.	Roger Meader	Coos-Curry 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.	Ray Ellis	Lincoln Electric Cooperative	WECC	3
10.	Annie Terracciano	Northern Lights Inc.	WECC	3
11.	Aleka Scott	PNGC Power	WECC	4, 8
12.	Heber Carpenter	Raft River Electric Cooperative	WECC	3
13.	Steve Eldrige	Umatilla Electric Cooperative	WECC	1, 3
14.	Marc Farmer	West Oregon Electric Cooperative	WECC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13 Group	Brandy A. Dunn	Western Area Power Administration										

No additional members listed.

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14 Group	Cole Brodine	Nebraska Public Power District										

No additional members listed.

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

1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Joe Stonecipher	Beaches Energy Services	FRCC	1
6.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
7.	Randy Hahn	Ocala Utility Services	FRCC	3

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

1.	Carlton Bradshaw	Delmarva Power & Light	RFC	1, 3

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

1.	Dean	Bender	WECC	1
2.	Heather	Laslo	WECC	1
3.	Brenda	Vasbinder	WECC	1

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

4.	Greg	Vassallo	WECC	1
5.	Mason	Bibles	WECC	1
6.	Jenifur	Rancourt	WECC	1, 3, 5, 6
7.	Rebecca	Berdahl	WECC	3
8.	Jason	Burt	WECC	1

18	Group	Sandra ShFaffer	PacifiCorp										

No additional members listed.

19	Group	Annette M. Bannon	PPL Supply NERC Registered Organizations					X					

1.	Leland McMillan	PPL Montana, LLC	WECC	5
2.	Donald Lock	PPL Generation, LLC	RFC	5

20	Group	WILL SMITH	MRO NSRF	X		X		X	X				

1.	MAHMOOD SAFI	OPPD	MRO	1, 3, 5, 6
2.	CHUCK LAWRENCE	ATC	MRO	1
3.	TOM WEBB	WPS	MRO	3, 4, 5, 6
4.	JODI JENSON	WAPA	MRO	1, 6
5.	KEN GOLDSMITH	ALTW	MRO	4
6.	ALICE IRELAND	XCEL(NSP)	MRO	1, 3, 5, 6
7.	DAVE RUDOLPH	BEPC	MRO	1, 3, 5, 6
8.	ERIC RUSKAMP	LES	MRO	1, 3, 5, 6
9.	JOE DEPOORTER	MGE	MRO	3, 4, 5, 6
10.	SCOTT NICKELS	RPU	MRO	4
11.	TERRY HARBOUR	MEC	MRO	3, 5, 6, 1
12.	MARIE KNOX	MISO	MRO	2
13.	LEE KITTELSON	OTP	MRO	1, 3, 4, 5
14.	SCOTT BOS	MPW	MRO	1, 3, 5, 6
15.	TONY EDDLEMAN	NPPD	MRO	1, 3, 5
16.	MIKE BRYTOWSKI	GRE	MRO	1, 3, 5, 6
17.	THERESA ALLARD	MPC	MRO	1, 3, 5, 6

21	Group	Jason Marshall	ACES Power Marketing Standards	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Collaborators										
1.	Shari Heino	Brazos Electric Power Cooperative, Inc.	SERC	1									
2.	Mohan Sachdeva	Buckeye Power, Inc.	RFC	3, 4									
3.	Erin Woods	East Kentucky Power Cooperative	SERC	1, 3, 5									
4.	Scott Brame	North Carolina Electric Membership Corporation	RFC	1, 3, 4, 5									
5.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4									
6.	Lindsay Shepard	Sunflower Electric Power Corporation	SPP	1									
7.	Clem Cassmeyer	Western Farmers Electric Cooperative	ERCOT	1, 5									
22	Group	Janet Smith	Arizona Public Service Company										
No additional members listed.													
23	Group	Antonio Grayson	Southern Company Generation										
No additional members listed.													
24	Group	Todd Moore	Kansas City Power & Light	X		X		X	X				
1.	Tim Hinken	Kansas City Power & Light	SPP	1, 3, 5, 6									
25	Individual	Brenda Frazer	Edison Mission Marketing & Trading	X				X					
26	Individual	Richard Tressler	Alber Corporation										
27	Individual	Russ Schneider	Flathead Electric Cooperative, Inc.			X	X						
28	Individual	Michael Falvo	Independent Electricity System Operator		X								
29	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X	X				
30	Individual	Michelle R D'Antuono	Ingleside Cogeneration LP					X					
31	Individual	Daniel Duff	Liberty Electric Power LLC					X					
32	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
33	Individual	Cristina Papuc	TransAlta Centralia Generation LLC					X					
34	Individual	Edward Davis	Entergy Services	X		X		X	X				
35	Individual	Glen Sutton	ATCO Electric Ltd	X									
36	Individual	Thad Ness	American Electric Power	X		X		X	X				
37	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
38	Individual	Bo Jones	Westar Energy	X		X		X	X				
39	Individual	Kirit Shah	Ameren	X		X		X	X				
40	Individual	Steve Alexanderson P.E.	Central Lincoln			X	X					X	
41	Individual	Chris Searles	BAE Batteries USA										
42	Individual	Andrew Gallo	City of Austin dba Austin Energy			X	X	X	X				
43	Individual	Chris Searles	BAE Batteries USA								X		
44	Individual	Martin Bauer	US Bureau of Reclamation					X					
45	Individual	Brian J. Murphy	NextEra Energy, Inc.	X		X		X	X				
46	Individual	Patrick Brown	Essential Power, LLC					X					
47	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
48	Individual	Brad Harris	CenterPoint Energy	X									
49	Individual	Anthony Jablonski	ReliabitliyFirst										X
50	Individual	Keira Kazmerski	Xcel Energy	X		X		X	X				
51	Individual	Greg Rowland	Duke Energy	X		X		X	X				
52	Individual	Martin Kaufman	ExxonMobil Research and Engineering	X				X					
53	Individual	Laurie Williams	PNM Resources	X		X							
54	Individual	Mauricio Guardado	Los Angeles Department of Water and Power	X		X		X	X				
55	Individual	Wayne E. Johnson	EPRI										
56	Individual	Maggy Powell	Constellation/Exelon	X		X		X	X				

1. **In response to comments, the PSMTSDT revised Requirement R1 to state that an entity's Protection System Maintenance Program (PSMP) shall include, for each Protection System component type, an identification of the maintenance method(s) used, and the identification of the relevant monitoring attributes applied. Do you agree with this change? If you do not agree, please provide specific suggestions for improvement.**

Summary Consideration: Many commenters were in agreement with this change.

Comments were offered that the definition of PSMP is incongruous with its use in Requirement R1; the SDT disagreed, and noted that the definition of a PSMP is linked to Requirement R1 in that the entity's program shall include one or all of the parameters in the definition. Requirement R1 requires that the entity establish their program, and is the foundation for the standard.

Other comments questioned why Requirement R1 includes the applicable level of monitoring for a Component when this is also listed in the Component attributes within the tables; the SDT explained that the discussion in Requirement R1 is to assure that the monitoring is present to support the intervals and activities used.

The SDT responded to concerns regarding the use, within Requirement R1, of "Component Type" by noting that this term allows entities latitude in how they define their PSMP.

Other commenters noted that Requirement R1 does not require that entities maintain their Components; and is, therefore, administrative and should have a lower VRF. The SDT responded that Requirement R1 is the foundation of the standard; and, therefore, the VRF is appropriate.

The SDT accepted a suggestion to remove the imbedded parenthetical within Requirement R1.

Several comments were submitted that were unrelated to this question.

Organization	Yes or No	Question 1 Comment
Pacific Gas and Electric Company	Negative	PG&E thanks the drafting team for their efforts. PG&E agrees with overall changes to the standard and sees the current draft as an improvement over the prior draft, on which PG&E voted affirmative. PG&E however will vote negative on the current ballot due to recent experience and trouble with trying to implement the intercell connection resistance test for NiCad batteries as specified in Table 1-4c of PRC-005-2. PG&E has experienced trouble trying to implement the "Battery intercell or unit-to-unit connection resistance" maintenance activity for certain NiCad battery types. In

Organization	Yes or No	Question 1 Comment
		these cases the battery post was not exposed and was entirely covered by the intercell strap. The battery post protruded minimally from the battery and could not be accessed with a probe. PG&E requests clarification on this requirement and that provision be provided to accommodate existing battery systems without requiring modification to the battery system. Modification of the battery system to access the battery post places a hardship on the battery owner, may compromise the battery design, and ultimately may require replacing the battery to allow fulfilling the maintenance requirement. One solution may be to allow measuring intercell connection resistance from the battery post bolt when the battery post is not accessible. While this is not the optimal approach, it may still be effective since the presence of corrosion would likely show up between both the battery post and bolt and also between the bolt and intercell strap. Trending the resistance from bolt-to-bolt may still be effective in determining an increasing resistance from post-to-post. PG&E suggests the following language: Table 1-4c Verify - Battery intercell or unit-to-unit connection resistance where battery post is accessible. Where battery post is not accessible measure intercell or unit-to-unit connection resistance from bolt-to-bolt or nearest connection to the battery post.
Response: Thank you for your comment. The SDT believes that the Maintenance Activities in Table 1-4c are explicit as to the required activity and are necessary to ensure the integrity of the station battery. The SDT believes the activity you discuss is not an effective method to satisfy the intent of the requirement in Table 1-4c; and the team suggests that you consult the manufacturer of your battery system to investigate how to meet the requirement.		
Seminole Electric Cooperative, Inc.	Negative	Seminole recommends the SDT re-consider an interval of 12 calendar years for the component in row 2, of Table 1-5. The maximum maintenance interval for "Electromechanical lockout 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 stable system configuration. Increasing the time the BES is in

Organization	Yes or No	Question 1 Comment
		a less stable system configuration also increases the probability of a low frequency, high impact event occurring. 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. Therefore, the Maximum Maintenance Interval should be 12 years for lockout relays. It appears that the SDT is trying to address a specific type of lockout relay with the 6 year interval that consists of a longer operating rod lockout that is subject to binding when called upon to operate. Why is it necessary to include all lockout relays when only a very specific segment of all lockout relays is subject to this one problem? Maybe a unique category of these specific types of lockouts, subject to operating rod binding should be specified at 6 years, with other lockouts not subject to this problem using a common interval like other protective components of 12 years. We sincerely hope that the SDT will consider these positive changes.
Response: Thank you for your comment. The SDT believes that electromechanical lock-out relays (86) (used to convey the tripping current to the trip coils), regardless of the manufacturer, need to be electrically operated to prove the capability of the device to change state. The application of lockouts is typically associated with equipment limited having remote backup protection (Generators/Transformers) or higher system consequences if remote backup is called upon to operate (Buses/Breakers). A failure of a lockout to function results in decreased stability and has a higher outage impact. These tests need to be accomplished at least every six years, unless PBM methodology is applied. The contacts on the 86 that change state to pass on the trip current to a breaker trip coil need only be checked every 12 years with the control circuitry.		
Tampa Electric Co.	Negative	The requirement to periodically test Control circuits will negatively impact reliability. The possibility of lifted wires being properly re-landed or test links being left open following testing will cause more misoperations than the finding of failed devices prevents. The outages required to do the testing will limit available transmission capability and therefore affect markets negatively for no reliability enhancement.
Response: Thank you for your comment. The SDT believes that periodic testing of control circuits is a vital part of assuring proper		

Organization	Yes or No	Question 1 Comment
operation of a protective relay system. There are several methods of accomplishing this testing. Where portions of the circuit are isolated for testing, procedures should be in place to assure proper restoration of the circuit.		
Tennessee Valley Authority	Negative	1. Regarding the functional test required every 3 months for “unmonitored communication systems” in Table 1-2 of the PRC-005-2 Draft. TVA feels that a Maximum Maintenance Interval for the Functional Test should be every 12 months until auto-checkback has been fully implemented by the utility. 2. The Implementation Plan for PRC-005-2 Step 4 on Page 2 states: “The Implementation Schedule set forth in this document requires that entities develop their revised Protection System Maintenance Program within twelve (12) months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption. This anticipates that it will take approximately twelve (12) months to achieve regulatory approvals following adoption by the NERC Board of Trustees.” TVA feels that this is not sufficient time to implement full auto-checkback capability at some utilities. The time schedule of twelve (12) months should be forty-eight (48) months following applicable regulatory approvals
Response: Thank you for your comments. 1) The SDT believes the four-month interval is proper for unmonitored communications systems. The activity related to this interval is to verify basic operating status. 2) The Implementation Plan is intended to facilitate implementation of the standard, not to facilitate modifications to meet the requirements of the standard.		
U.S. Bureau of Reclamation	Negative	1. The definition for PSMP is incongruous with the use of the PSMP in Requirement R1. Requirement R1, including the Measure and VSL focus on the identification of maintenance method of the Component types and not that the PSMP is in fact being used for maintenance of the component. 2. The requirement R5 indicates the entity has to "demonstrate" efforts to correct

Organization	Yes or No	Question 1 Comment
		identified unresolved maintenance issues. The measure M5 described documentation of the efforts. The requirement language should be explicit. Does the standard want a demonstration which implies active role of the entity to prove what it is doing, or to provide documentation of the activities underway to correct deficiencies? The language in the requirement should be altered to "Each Transmission Owner, Generator Owner, and Distribution Provider shall prepare a CAP for each identified Unresolved Maintenance Issue." A second requirement is needed to require that "Each Transmission Owner, Generator Owner, and Distribution Provider shall complete its CAP to correct the identified Unresolved Maintenance Issues." The measures would need to be adjusted accordingly to reflect the CAP and evidence that the entity completed the CAP. 3. Re Terms defined for use only within PRC-005-2: The standard provides definitions which will not be incorporated into the Glossary of Terms. This would allow the definitions as used in this standard to conflict with the definition used in other standards if this practice becomes more widespread and would reduce the cohesiveness of the standard set. 4. Re The definition of Components: The standard defined what constitutes a control circuit as a component type with "Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices." The standard then modified the definition by allowing "a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry." The definition should not be dependent upon practice. This makes the definition a fill in the blank definition. Either eliminate the allowance or remove the definition of control circuit.
Response: Thank you for your comments.		

Organization	Yes or No	Question 1 Comment
1. The SDT believes that the definition of a PSMP is linked to Requirement R1 in that the entity's program shall include one or all of the parameters in the definition. Requirement R1 requires that the entity establish their program, and is the foundation for the standard. Requirements R3-R4 address implementation of the entity's PSMP. 2. Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase, "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requires battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "Unresolved Maintenance Issue" has been modified to add a clarifying phrase that the deficiency, "…cannot be corrected during the maintenance interval." 3. The standard specifies that the terms used are intended for this document only; and, therefore, there should not be any conflict with their use in any other PRC standard. **4.** The intent of the different means of identifying control circuitry was to accommodate various entities' philosophies on testing of these circuits. Regardless of how an entity chooses to identify their control circuitry, the entity must meet the requirements of the standard regarding maintenance of control circuitry.		
DTE Energy	No	DECo does not agree. With the exception of station batteries, all components should be tested as a scheme to assure that all components are working together as designed, so the PSMP should not be required for each component type.
Response: Thank you for your comment. A PSMP allows for each component within a protective relay scheme to have a differing maintenance interval allowing for unit or station outages. A company's PSMP can perform maintenance on all the components within a particular relay scheme, but that would require the shortest of the maintenance intervals.		
PNGC Comment Group	No	Specifying "by component type" appears confusing. It seems possible that some pieces of equipment from the same component type could end up in a different type of maintenance program. We suggest changing to "by component or component

Organization	Yes or No	Question 1 Comment
		type" when entities determine the maintenance method in their PSMP.
Response: Thank you for your comment. The SDT believes that it is acceptable for an entity to subdivide components within a component type, if desired. The SDT does not want to remove that latitude.		
Nebraska Public Power District	No	1. Since auditors will be able to request documentation necessary to validate the inclusion of the device within the appropriate level of monitoring, why does the program document require listing level of monitoring and component attributes? (Concerned about the burden of maintaining lists of components in a program document that are alike but have different levels of monitoring. Ex: Monitored and unmonitored microprocessor relays) 2. For identification of the relevant monitoring attributes applied can a single specification document suffice for similar relay types such as one document for SEL relays? 3. For trip circuit monitoring can a standard document be used for a group of similar schemes?
Response: Thank you for your comments. See Section 6.1 of the Supplementary Reference and FAQ document for a discussion of this topic. 1. The requirement to list component attributes is designed to support a company's program for the maintenance intervals used. 2. The SDT concurs with using a single specification document for similar equipment. 3. The SDT concurs with a standard document for trip circuit monitoring when consistent practices are present.		
Flathead Electric Cooperative, Inc.	No	1. Specifying "by component type" appears confusing. It seems possible that some pieces of equipment from the same component type could end up in a different type of maintenance program. We suggest changing to "by component or component type" when entities determine the maintenance method in their PSMP. 2. Generally, have concerns with all the new definitions except the NERC

Organization	Yes or No	Question 1 Comment
		definition of Protection System. The approach to creating new definitions of plain language in a standard should be avoided.
Response: Thank you for your comments. 1. The SDT believes it is acceptable for an entity to subdivide components within a component type, if desired. The SDT does not want to remove that latitude. 2. The standard specifies that the terms used are intended for this document only; and, therefore, there should not be any conflict with their use in any other PRC standard.		
American Electric Power	No	R1.1 binds you to the activities in the table, but our system is comprised of elements (such as a Plant Control Systems), that are not included in the table. As a result, it is not clear how an entity could develop an SPS that satisfies both the requirement and our system.
Response: Thank you for your comment. IEEE defines a relay as: "An electric device designed to respond to input conditions in a prescribed manner and after specified conditions are met to cause contact operation or similar abrupt change in associated electric control circuits." The SDT believes that protective relay functions that are embedded in control systems and/or SPSs are a part of this standard and are, therefore, under the same requirements as dedicated, stand-alone protective relays. It is left to the entity to determine how to align these requirements with operational concerns.		
Manitoba Hydro	No	Please see comments provided in Question 4.
US Bureau of Reclamation	No	The requirement R1 states that the PSMP must identify how the component is to be maintained, using time based or performance based or a combination. While R1 requires a PSMP, there is no measure that the PSMP is used for actually maintaining the components, other than for documenting which maintenance method is being used. The purpose of R1 is therefore administrative. Since there is no measure for the use of the PSMP, why is the entity required to develop the PSMP as defined? There is no VSL for R1 which requires that the entity establish a PSMP. Since there is no severity level associated a PSMP that does not contain one of the required activities it supports elimination of the definition of PSMP. PSMP definition is also weak and does not match with the VSL that the PSMP identify the maintenance method of the protection system component types. The definition is that PSMP

Organization	Yes or No	Question 1 Comment
		which must include: "A maintenance program for a specific component includes one or more of the following activities: o Verify- Determine that the component is functioning correctly. o Monitor - Observe the routine in-service operation of the component. o Test - Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. o Inspect - Detect visible signs of component failure, reduced performance and degradation. o Calibrate- Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement." Since requirement 1 essentially only requires identification of which maintenance method is to be used, there is no need for the definition. It no longer matters how the device's functionality is determined as long as it is performed on a time based or performance based method. This approach may be lowering the reliability level associated with the protection system maintenance. Since the definition of PSMP is that only one of the 5 activities is needed, is seems that one could select to "Monitor" the in-service operation of the component on a time base and no further action is needed. So that could mean observe that the relay has power and was not misoperating every six years and maintenance is performed. A PSMP is as defined does not help the reliability. It would be better require the PSMP include as a minimum all five activities defined as well as defining the maintenance method used (time based, performance based, or a combination). There needs to be a requirement that the PSMP needs to be developed. Then Requirement 1 would be to implement the PSMP.
Response: Thank you for your comments. Requirement R1 requires that the entity establishes a PSMP (with the specified attributes), and is the foundation for the standard; thus, Requirement R1 is not administrative, as without a PSMP, there is nothing on which to base the remainder of the standard. Requirements R3-R4 address implementation of the entity's PSMP.		
ExxonMobil Research and Engineering	No	As written, the current draft of PRC-005-2 discriminates against smaller entities that do not have a population size of 60 for each component type. Historical records provide an accurate account of how specific components have performed in their installed environment. For a set population size, increasing the number of historical data points should improve the accuracy of an entity's calculated mean time between failures, so, if you increase the period over which the historical data must

Organization	Yes or No	Question 1 Comment
		be evaluated, you can compensate for a smaller segment population size. The SDT's current draft prevents smaller entities from using a larger historical data set to make up for a smaller population size when developing a performance based protective system maintenance and testing program. The SDT should reconsider allowing smaller entities to use historical records that extend for period longer than a single year in the development of a performance based program .
Response: Thank you for your comment. Small entities are permitted to aggregate their components with similar components of other entities to meet the component populations, as long as the programs are (and remain) similar – See Section 9 of the Supplementary Reference and FAQ document and the associated footnote to Attachment A. Decreasing the component population below the requirements of Attachment A will result in an unsound program due to component populations that are not statistically significant. The Supplementary Reference and FAQ document states, "Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM but does not own 60 units to comprise a population then that asset owner may combine data from other asset owners until the needed 60 units is aggregated."		
EPRI	No	My comments are not to the point of dividing the requirements but the guidance in the PSMP tables are not technically valid for maintaining stationary battery cells. Internal ohmic measurements are related to the condition of an individual cell and not a battery bank. Also, there is not a direct correlation to ohmic measurements and battery or cell capacity. Ohmic measurements can provide an indication of a problem cell and point to a cell that should be tested. There also seems to be a misconception as to the type of capacity test that should be required. There are typically two types of tests done on batteries: service tests and performance tests. Service test are done to determine if a battery (group of cells) can meet its duty cycle whereas, a performance test is intended to test a battery against the manufacturers curve to make a determination of when the battery should be replaced. A battery could technically still meet its duty cycle but have reduced capacity. This simply means that the sizing was done properly, maintenance is timely, and there should be a timely replacement of the cells.
Response: Thank you for your comment. The drafting team agrees with statements by you and others concerning the true capacity of the station battery and relating it to internal ohmic measurements. Tables 1-4a, 1-4b and 1-4c have been modified for clarity, and		

Organization	Yes or No	Question 1 Comment
the Supplemental Reference and FAQ document has been modified to further elaborate on these concerns.		
Public Utility District No. 1 of Okanogan County	Affirmative	OCPD would like some clarification with regards to the Power Wave concept. Currently in Table 1.1 and Table 3 it states, “Voltage and/or current waveform sampling three or more times per power cycle, and conversion of samples to numeric values for measurement calculations by microprocessor electronics." OCPD feels that it might be better stated as simply 60 Hz.
Response: Thank you for your comment. The values for waveform sampling are intended to be verified by referencing a specific manufacturer’s specifications.		
ACES Power Marketing Standards Collaborators	Yes	Is the use of parentheticals within another set of parentheticals in Part 1.1 intentional? It is unusual to do this and a little confusing.
Response: Thank you for your comment. The SDT agrees with your suggestion, and made the following change: “Identify which maintenance method (time-based, performance-based per PRC-005 Attachment A, or a combination) is used to address each Protection System component type.”		
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration agrees that a Compliance Authority should be alerted to those component types which have been assigned extended maintenance intervals because they use some form of monitoring. We also agree that it is appropriate that the PSMP list the relevant monitoring attributes in these cases, so they can be confirmed to be consistent with the criteria in PRC-005-2’s interval tables.
Response: Thank you for your comments.		
Northeast Power Coordinating Council	Yes	
MRO NSRF	Yes	
Tacoma Public Utilities	Yes	
Imperial Irrigation District (IID)	Yes	
Dominion	Yes	
Texas Reliability Entity	Yes	
Southwest Power Pool Standards	Yes	

Organization	Yes or No	Question 1 Comment
Development Team		
Tennessee Valley Authority	Yes	
FirstEnergy	Yes	
Western Area Power Administration	Yes	
Pepco Holdings Inc. & Affiliates	Yes	
Bonneville Power Administration	Yes	
PacifiCorp	Yes	See comments under #4.
PPL Supply NERC Registered Organizations	Yes	
MRO NSRF	Yes	
Arizona Public Service Company	Yes	
Southern Company Generation	Yes	
Kansas City Power & Light	Yes	
Edison Mission Marketing & Trading	Yes	
Alber Corporation	Yes	
Independent Electricity System Operator	Yes	
Liberty Electric Power LLC	Yes	
TransAlta Centralia Generation LLC	Yes	
Entergy Services	Yes	
ATCO Electric Ltd	Yes	
Westar Energy	Yes	
Ameren	Yes	
Central Lincoln	Yes	
BAE Batteries USA	Yes	
City of Austin dba Austin Energy	Yes	

Organization	Yes or No	Question 1 Comment
BAE Batteries USA	Yes	
Essential Power, LLC	Yes	
American Transmission Company, LLC	Yes	
CenterPoint Energy	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
PNM Resources	Yes	
Los Angeles Department of Water and Power	Yes	
Response: Thank you for your support.		

2. **As a result of the changes to Requirement R1, the previous Requirement R3 was separated into three requirements:**

   a. **Requirement R3 now requires that an entity utilizing a time-based program maintain its Protection System components in accordance with the maximum maintenance intervals listed in the tables. This change removes the compliance jeopardy associated with an entity having more stringent intervals (in its PSMP) than those listed in the tables.**

   b. **Requirement R4 (new) requires an entity utilizing a performance-based program maintain its Protection System components in accordance with its performance-based Protection System Maintenance Program.**

   c. **Requirement R5 (new) requires an entity to demonstrate efforts to correct identified unresolved maintenance issues. The previous language in Requirement R3 directed that an entity initiate resolution.**

   Do you agree with this change? If you do not agree, please provide specific suggestions for improvement.

Summary Consideration: Many commenters were in agreement with this change.

Numerous comments were offered relative to subject and definition of "Unresolved Maintenance Issues," per Requirement R5. As a result of these comments, the definition of this term was modified to include the phrase, "… cannot be corrected during the maintenance interval…" For those commenters objecting to the concept of Unresolved Maintenance Issues, the SDT explained the rationale behind the concept.

Several comments were submitted that were unrelated to this question.

Organization	Yes or No	Question 2 Comment
Beaches Energy Services	Negative	The applicability of the standard should be modified to reflect the FERC approved interpretation PRC-005-1b Appendix 1 that basically says that applicable Protection Systems are those that protect a BES Element AND trip a BES Element. The interpretation states: The applicability as currently stated will sweep in distribution protection: "4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)" Many (most) network distribution systems that have more than one source into a distribution network will have reverse power relays to detect faults on the BES

Organization	Yes or No	Question 2 Comment
		and trip the step-down transformer to prevent feedback from the distribution to the fault on the BES. This is not a BES reliability issue, but more of a safety issue and distribution voltage issue. These relays would be subject to the standard as the applicability is currently written, but, should not be and they are currently not within the scope of PRC-005-1b Appendix 1 because the step-down transformer (non-BES) is tripped and not a BES Element (hence, the "and" condition of the interpretation is not met). There are many other related examples of distribution that might be networked or have distributed generation on a distribution circuit where such reverse power relays, or overcurrent relays with low pick-ups, are used for safety and distribution voltage control reasons and are not there for BES Reliability. To make matters worse, for these Reverse Power relays, it is pretty much impossible to meet PRC-023 because the intent of the relay is to make current flow unidirectional (e.g., only towards the distribution system) without regard for the rating of the elements feeding the distribution network. So, if these relays are swept in, and if they are on elements > 200 kV, then the entity would not be able to meet PRC-023 as that standard is currently written. So, the SDT should adopt the FERC approved interpretation.

Response: Thank you for your comment. The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, “transmission Protection System,” and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements.

To address your concern, the distribution protective devices and functions cited in this comment are not “installed for the purpose of detecting Faults on BES Elements” and would, therefore, not be subject to PRC-005-2. A relay used primarily for “safety and distribution voltage control reasons” is clearly not “installed for the purpose of detecting Faults on BES Elements.” The reverse power relay application described is also not “installed for the purpose of detecting Faults on BES Elements,” (the relays react to changes in power flow direction, which may or may not be due to a Fault) but for the purpose of preventing feedback from the distribution system to the transmission system.

Please see the PRC-005-2 Supplementary Reference and FAQ, Section 2.3, for a more detailed discussion of this issue.

Organization	Yes or No	Question 2 Comment
Fort Pierce Utilities Authority	Negative	1. The applicability of the standard should be modified to reflect the FERC approved interpretation PRC-005-1b Appendix 1 that basically says that applicable Protection Systems are those that protect a BES Element AND trip a BES Element. The applicability as currently stated will sweep in distribution protection: “4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).” Most network distribution systems that have more than one source into a distribution network will have reverse power relays to detect faults on the BES and trip the step-down transformer to prevent feedback from the distribution to the fault on the BES. This is not a BES reliability issue, but more of a safety and distribution voltage issue. These relays would be subject to the standard as the applicability is currently written, but, should not be and they are currently not within the scope of PRC-005-1b Appendix 1 because the step-down transformer (non-BES) is tripped and not a BES Element (hence, the "and" condition of the interpretation is not met). 2. There are many other related examples of distribution that might be networked or have distributed generation on a distribution circuit where such reverse power relays, or overcurrent relays with low pick-ups, are used for safety and distribution voltage control reasons and are not there for BES Reliability. To make matters worse, for these Reverse Power relays, it is pretty much impossible to meet PRC-023 because the intent of the relay is to make current flow unidirectional (e.g., only towards the distribution system) without regard for the rating of the elements feeding the distribution network. So, if these relays are swept in, and if they are on elements > 200

Organization	Yes or No	Question 2 Comment
		kV, then the entity would not be able to meet PRC-023 as that standard is currently written. FPUA recommends the SDT should adopt the FERC approved interpretation. 3. Another concern is regarding the sudden pressure relays. These had been out of the scope in all previous draft versions of PRC-005-2 because these do not measure electrical quantities. However, the SDT just added a requirement to test the trip path from the sudden pressure device, arguing that it is captured by the definition of Protection Systems. This inconsistency does not make sense and could create “grey areas” for other devices that can trip for low oil level or high temperature, among others. By their nature, sudden pressure devices are far less reliable than their associated control circuitry. I know of at least one large entity that disables sudden pressure relays on smaller transformers to cut down on nuisance alarms. If it is expected that non-electrically initiated devices may become part of some maintenance standard in the future, I think it would be premature for the SDT to address sudden pressure relays in PRC-005-2. 4. And lastly, page 77 of the Supplementary Reference has some text clarifying the requirement for establishing a baseline test: “For all new installations of Valve-Regulated Lead-Acid (VRLA) batteries and Vented Lead-Acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as designed, the establishment of the baseline as described above should be followed at the time of installation to insure the most accurate trending of the cell/unit.” This guidance does not recognize the fact that

Organization	Yes or No	Question 2 Comment
		some battery manufacturers recommend the baseline tests to be performed at some point in time after the install to allow the cell chemistry to stabilize after the initial freshening charge. The manual from a battery manufacturer (Enersys Powersafe) states that "The initial records are those readings taken after the battery has been in regular float service for 3 months (90 days). These should include the battery terminal float voltage and specific gravity reading of each cell corrected to 77F (25C), all cell voltages, the electrolyte level, temperature of one cell on each row of each rack, and cell-to-cell and terminal connection detail resistance readings. It is important that these readings be retained for future comparison". If an entity follows the manufacturer's recommendation, the above statements would lead an auditor to a finding of non-compliance because internal ohmic tests were not performed prior to placing a new battery string in service. A simple modification to the wording would eliminate the conflict.

Response: Thank you for your comments.

1. The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System," and notes that this term is not used within PRC-005-2; thus, the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements.
2. To address your concern, the distribution protective devices and functions cited in this comment are not "installed for the purpose of detecting Faults on BES Elements" and would, therefore, not be subject to PRC-005-2. A relay used primarily for "safety and distribution voltage control reasons" is clearly not "installed for the purpose of detecting Faults on BES Elements." The reverse power relay application described is also not "installed for the purpose of detecting Faults on BES Elements," (the relays react to changes in power flow direction, which may or may not be due to a Fault) but for the purpose of preventing feedback from the distribution system to the transmission system.

Organization	Yes or No	Question 2 Comment
Please see the PRC-005-2 Supplementary Reference and FAQ, Section 2.3, for a more detailed discussion of this issue. 3. DC trip circuit from a sudden pressure relay output to the trip coil of the interrupting device has always been included in the "Control circuitry" portion of a Protection System, and is discussed in Section 15.3 of the PRC-005-2 Supplementary Reference and FAQ document. In regards to including sudden pressure relays themselves, FERC, in Order 758, recently directed NERC to submit an informational filing providing a schedule for addressing sudden pressure relays in PRC-005. The NERC System Protection and Control Subcommittee (SPCS) worked with NERC staff to develop the informational filing, which was filed with FERC on April 12, 2012. Activities associated with the schedule submitted in the filing will be included in a final SAR to further develop PRC-005. A draft SAR for a second phase of this project is posted for information only at this time. 4. The drafting team revised the Supplemental Reference and FAQ document based on your recommendations.		
Imperial Irrigation District (IID)	No	IID disagree with item c. and does not believe item c increases the reliability of the BES. The maintenance issues will be resolved internally and should not be required as per compliance of the standard.
Response: Thank you for your comment. The practice of returning Protection System devices to good working order exists currently as a required element of a sound maintenance program as required by the existing Protection System maintenance and testing standard, PRC-005-1b. For reference, NERC Compliance Application Notice CAN-0043 (Posted Final 12/30/2011) directs Compliance Enforcement Authorities (CEAs) to "…look for relay test results or field records with annotations such as "as-found" readings or pass/fail results; if failed, then adjustments made. The maintenance record for adjustments may be requested".		
Texas Reliability Entity	No	New requirement R5 states that an entity shall "demonstrate efforts" to correct identified Unresolved Maintenance Issues. This falls short of requiring completion of any corrective actions for the unresolved maintenance issue. We suggest rewording to "Each Transmission Owner, Generator Owner, and Distribution Provider shall develop a corrective action plan and work timetable to address identified Unresolved Maintenance Issues. The Registered Entity shall complete resolution of Unresolved Maintenance Issues within the time frame identified in the Entity corrective action plan." If R5 is modified, then M5 and the VSL should also be modified accordingly.
Response: Thank you for your comment.		

Organization	Yes or No	Question 2 Comment
Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase, "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requires battery replacement as part of the long term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT believes corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "unresolved maintenance issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval."		
Nebraska Public Power District	No	The FAQ attempts to clarify the intent of "demonstrate efforts to correct", however, there is no explanation as to why this new term is preferable to the more concise "initiate resolution" term that was developed and agreed upon over the last year. In the Supplementary Reference and FAQ document there is a request for clarification and it is reprinted below. Please clarify what is meant by "...demonstrate efforts to correct an unresolved maintenance issue..."; why not measure the completion of the corrective action? Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a 6 month check. In instances such as one that requiring battery replacement as part of the long term resolution, it is highly unlikely that the battery could be replaced in time to meet the 6 calendar month requirement for this maintenance activity. The SDT does not believe entities should be found in violation of a maintenance program

Organization	Yes or No	Question 2 Comment
		requirement because of the inability to complete a remediation program within the original maintenance interval. The SDT does believe corrective actions should be timely but concludes it would be impossible to postulate all possible remediation projects and therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. I agree with this response and specifically the last sentence. This indicates that R5 "demonstrating efforts to correct unresolved issues" is too open ended and subjective and cannot be applied by enforcement in a consistent way. R5 should be removed from the standard.
Response: Thank you for your comment. Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase, "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requires battery replacement as part of the long term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT believes corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "unresolved maintenance issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval."		
Bonneville Power Administration	No	BPA believes that R5 is not worded in such a way that it can be easily or consistently audited.
Response: Thank you for your comment. Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and		

Organization	Yes or No	Question 2 Comment
yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requires battery replacement as part of the long term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT believes corrective actions should be timely but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "Unresolved Maintenance Issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval." Each entity must determine how to document the efforts to correct the Unresolved Maintenance Issue based on the specific issue and choice of remediation.		
PPL Supply NERC Registered Organizations	No	1. The maximum maintenance intervals in PRC-005-2 of 4 calendar months and 18 calendar months are not compatible with computerized maintenance-planning programs based on periodicity rather than elapsed time from the previous check. This situation could be addressed in a conservative fashion by performing work quarterly instead of at 4-month intervals, and annually in place of 18-month periods, which also provides often-needed flexibility as to scheduling the tasks. Inspections performed in April for Q2 and September for Q3 would not meet NERC's 4 calendar month criterion, however, and a similar problem exists for annual checks. The more-stringent compliance jeopardy cited above has therefore not been fully addressed. We recommend changing the 4 calendar months and 18 calendar months intervals to quarterly and annually respectively. 2. We consider addition of the expression, "causes the component to not meet the intended performance," to the previous draft's definition of Unresolved Maintenance Issues (UMIs) to constitute a step backwards, because of the unavoidable subjectivity involved in deciding whether or not a battery or other protection system device is unable to perform as intended. A battery with some "sparkle" on the plates due to sulfation would still be able to

Organization	Yes or No	Question 2 Comment
		perform adequately, for example, making this an issue to watch but not an UMI. It is impractical to provide strict, quantitative, UMI-threshold performance limits for every piece of equipment in a Protection System and every situation that may arise, however. The concept of an UMI has some appeal from a common-sense point of view; but as a regulation it is impractical and, given the breadth of the topic at hand, is likely to remain so regardless of alternative phrasing that might be attempted.
Response: Thank you for your comment. 1. The SDT believes that management issues associated with computerized maintenance management programs can be adapted to provide maintenance triggers consistent with the intervals established in the tables. Many of these systems offer the ability for the user to create custom algorithms to trigger the desired work order, reminder, or alarm, etc. The SDT also believes the four calendar-month and 18-calendar-month intervals are appropriate for the relative Protection System components. An entity may utilize the abbreviated intervals, such as you suggest, as long as they meet the explicit requirements and intervals established in the standard. **2.** The consideration of "meet the intended performance" is an issue for an entity to determine subjectively. This consideration depends heavily upon the nature of observed anomaly and upon the actual intended performance.		
Arizona Public Service Company	No	The standard does not provide basis for the enumerated "maximum allowable interval that is appropriate to the type of the protection system and its impact on the reliability of the Bulk-Power System." An example of such an approach is the Standard Technical Specifications in use by the nuclear power industry; e.g., NUREG 1432, volume 2. While we are supportive of the changes the SDT has made, APS is concerned the draft Standard will not give entities the flexibility to continue to improve reliability based on changing industry norms and best practices. When technology changes for the better, industry will need the flexibility to optimize use of the new technology while still maintaining an appropriate level of reliability. Lack of defined bases for intervals will prevent technically sound revision to maintenance practices.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. The SDT established the maximum maintenance intervals for each Protection System component subject to the standard based upon research performed by the NERC System Protection and Control Subcommittee and "best practice" input from industry. The base intervals are extended in consideration of modern monitoring capabilities and new technologies. These extended intervals range from "12 calendar years" to "No periodic maintenance specified." Consistent with the FERC directive of intervals being "…appropriate to the type of protection system and its impact on the reliability of the Bulk Power System," the SDT did not provide a "No periodic maintenance specified" extended interval for high reliability impact devices, such as protective relays; but rather stipulates a six-calendar-year interval for unmonitored electromechanical and unmonitored microprocessor relays, and a 12-calendar-year verification of monitored microprocessor relays. Please see Section 8.3 of the Supplementary Reference and FAQ document for a more detailed discussion of this issue.		
Southern Company Generation	No	1. The change made to R3 was a good move. Entities should be allowed the flexibility to build grace periods into their maintenance programs to assist them in meeting common national standards for maintenance activities and intervals. 2. If possible, elimination of all possible uncertainty in the auditability of requirement R5 is desired. We prefer eliminating this requirement R5 altogether to the proposed draft that includes a requirement to demonstrate efforts to correct identified unresolved maintenance issues.
Response: 1. Thank you for your comment and support. 2. Returning Protection System devices to good working order exists currently as a required element of a sound maintenance program subject to the existing Protection System Maintenance and Testing Standard, PRC-005-1b. For reference, NERC Compliance Application Notice CAN-0043 (Posted Final 12/30/2011) directs Compliance Enforcement Authorities (CEAs) to "…look for relay test results or field records with annotations such as "as-found" readings or pass/fail results; if failed, then adjustments made. The maintenance record for adjustments may be requested". Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside of the scope of		

Organization	Yes or No	Question 2 Comment
this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requires battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT believes corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "unresolved maintenance issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval."		
Ingleside Cogeneration LP	No	1. Ingleside Cogeneration LP strongly agrees with the change made to the language in R1 and R3 specifying that compliance is measured against the PRC-005-2's interval tables wherever time-based methods are used. The intervals were carefully designed to assure an acceptable level of BES reliability, and the regulatory authorities must be prepared to stand by them. Furthermore, a Registered Entity who may establish tighter intervals for their own internal purposes should be encouraged to do so - and without a threat of a violation hanging over their heads. 2. We also agree with the need to add a new requirement (R4) which applies to those entities that choose to use a performance-based system to determine some of their maintenance intervals. It logically maps back to requirement R2 which states that the calculated intervals must be documented in the PSMP. 3. We cannot agree with the language used in R5, which, in its previous form under R3, had specified only that the Protection System owner "initiate

Organization	Yes or No	Question 2 Comment
		resolution” to correct identified unresolved maintenance issues. We were actually comfortable with this language as it was unambiguous that progress did not need to be tracked start-to-finish. We would like to propose adding a phrase that tracks the statement in M5; which we find acceptable. This would result in the following: R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall demonstrate THAT IT HAS UNDERTAKEN <our emphasis> efforts to correct identified Unresolved Maintenance Issues.
Response: 1. Thank you for your comment and support. 2. Thank you for your comment and support. 3. The SDT believes corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. For the Compliance Monitoring Authority to be confident that the corrective action is being implemented, the entity should expect to demonstrate progress toward correcting the Unresolved Maintenance Issue, such as the evidence suggested in Measure M5 (with additional suggested evidence added).		
American Electric Power	No	1. R3: Table 1-5 notes a “mitigating device” as part of component attributes. Such a phrase could be open to interpretation and needs to be clearly defined. 2. Table 1-3, Maintenance Activities - there is nothing specifically regarding accuracy. Suggest incorporating the definition of “verify” as used in the FAQ or perhaps something similar to “verify values are as expected”. 3. R5: We understand the drafting team’s desire to deal with unresolved maintenance issues, however it is not clear how the adequacy of resolving

Organization	Yes or No	Question 2 Comment
		those issues would be determined by an auditor. If these kinds of efforts are going to be scrutinized, there needs to be some sort of boundaries established so that it is clear how unresolved maintenance issues would be evaluated.
Response: Thank you for your comment. *1.* The SDT intended that "mitigating devices" address actions of SPSs, which may include activities beyond tripping of interrupting devices. For example, SPSs may perform actions like generation run-back or generation fast-valving. 2. 'Verify" is a term expressed in the PSMP definition, and the use of the term in Table 1-3 indicates that the accuracy needs to be 'whatever is necessary' for proper functioning of the connected relays. **3.** There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT believes corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues. Measure M5 suggests some examples of evidence.		
US Bureau of Reclamation	No	The Requirement R5 indicates the entity has to "demonstrate" efforts to correct identified unresolved maintenance issues. The measure M5 described documentation of the efforts. The requirement language should be explicit. Does the standard want a demonstration which implies active role of the entity to prove what it is doing, or to provide documentation of the activities underway to correct deficiencies? The language in the requirement should be altered to "Each Transmission Owner, Generator Owner, and Distribution Provider shall prepare a CAP for each identified Unresolved Maintenance Issue." A second requirement is needed to require that "Each Transmission Owner, Generator Owner, and Distribution Provider shall complete its CAP to correct the identified Unresolved Maintenance Issues." The measures would need to be adjusted accordingly to reflect the CAP and evidence that the entity completed the CAP.
Response: Thank you for your comment. The term within Requirement R5, "… demonstrate efforts …" is intended for both – that the entities are acting to correct the deficiency and also (to prove compliance) maintaining documentation of the activities underway to		

Organization	Yes or No	Question 2 Comment
correct the deficiency. The SDT elected to not require a "**Corrective Action Plan**" as defined in the NERC Glossary of Terms to avoid much of the systemic, ongoing documentation attendant to that term. However, if an entity wishes to use a Corrective Action Plan as defined, that would be an acceptable method of meeting Requirement R5.		
Essential Power, LLC	No	The change to R3 is too restrictive, and removes the registered entity's ability to better define its own intervals based on its own experience and system characteristics. The comments regarding a CEA's enforcement of an RE's more stringent internal intervals is not indicative of an issue with the Requirement, but with the way in which it is enforced.
Response: Thank you for your comment. Requirement R3 still allows entities flexibility within their own Protection System Maintenance and Testing Program (PSMP), and only restricts an entity's establishment of intervals that are greater than those specified in the tables. For example, an entity may choose to establish, in its own PSMP, testing of a specific type or model of electromechanical relay more frequently than the six-calendar-year interval specified in Table 1-1 of PRC-005-2. However, should some issue come up that affects the entity's ability to complete testing of those devices within their programs established interval, but they are able complete the testing within the maximum maintenance interval provided by the standard, the standard explicitly establishes that they will not be found non-compliant for missing their own, more stringent interval.		
Xcel Energy	No	We agree with the changes to R3 and the new R4 requirement but disagree with the wording change in the new R5 requirement. The difference between "initiate resolution" and "demonstrate efforts to correct identified unresolved maintenance issues" is very unclear. Please clarify the SDT's intent with this subtle wording change. In our opinion, it would be fairly obvious if an entity met a requirement to "initiate resolution" and, thus, this would be easily measurable requirement. It seems that the phrase "demonstrate efforts to correct identified unresolved maintenance issues" will be open to more auditor judgment as to what constitutes adequate efforts to correct a deficiency and thus makes the measurement of meeting this requirement far more arbitrary. If this is not the intent, then why bother with the wording change? Furthermore, CEAs should realize that entities already have strong financial incentives in correcting identified unresolved maintenance issues to minimize the risk of costly equipment damage or equally costly outages of critical equipment. Delays in correcting identified

Organization	Yes or No	Question 2 Comment
		unresolved maintenance issues are seldom driven by cost avoidance and are more likely driven by the time it takes to develop, engineer and/or procure a better solution to a problem. Prompt band-aid type fixes are not necessarily desirable fixes and the wording of R5 should not promote the band-aid approach to the correction of a problem.
Response: Thank you for your comment and your support on Requirements R3 and R4. Requirement R5 is expressly focused on allowing entities to resolve deficiencies in an effective manner, rather than performing "band-aid" fixes. Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the recognition that more complex unresolved maintenance issues could require more time to resolve effectively than there is time remaining in the maintenance interval, yet the problems must eventually be resolved. The SDT believes that corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "unresolved maintenance issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval."		
ExxonMobil Research and Engineering	No	As written, the current draft of PRC-005-2 discriminates against smaller entities that do not have a population size of 60 for each component type. Historical records provide an accurate account of how specific components have performed in their installed environment. For a set population size, increasing the number of historical data points should improve the accuracy of an entity's calculated mean time between failures, so, if you increase the period over which the historical data must be evaluated, you can compensate for a smaller segment population size. The SDT's current draft prevents smaller entities from using a larger historical data set to make up for a smaller population size when developing a performance based protective system maintenance and testing program. The SDT should reconsider allowing smaller entities to use historical records that extend for period longer than a single year in the development of a performance based program.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment. Small entities are permitted to aggregate their components with similar components of other entities to meet the component populations, as long as the programs are (and remain) similar – See Section 9 of the Supplementary Reference and FAQ document and the associated footnote to Attachment A. Decreasing the component population below the requirements of Attachment A will result in an unsound program due to component populations that are not statistically significant. The Supplementary Reference and FAQ document states, "Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM but does not own 60 units to comprise a population then that asset owner may combine data from other asset owners until the needed 60 units is aggregated." Historical data may be good for trending, but may not be suitable for judging current maintenance program effectiveness.		
EPRI	No	See comments in question 1
Constellation/Exelon	No	While we are fine with the structural change to separate the requirements out further, we have concerns with the content of the requirements. R5/M5 • M5 needs further clarity to reflect the intended compliance obligation for R5. In previous comments, Constellation expressed concern that compliance obligation for R5 implied a greater level of completion in attending to an identified "deficiency." We pointed out that the severity of the "deficiency" found will dictate the method and timing of a "follow up correction action". In response to the comment, the SDT stated that "PRC-005-2 only requires the entity "... initiate resolution" of the issue found." The SDT revision of R5 and M5 is an improvement; however, changes to M5 are needs to clarify that efforts to correct do not require demonstration that those efforts have concluded. • A revision to the language will clarify the SDT intent. Please consider use of the following language: R5. Each Transmission Owner, Generator Owner, and Distribution Provider shall correct or initiate resolution of identified Unresolved Maintenance Issues. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] M5. Each Transmission

Organization	Yes or No	Question 2 Comment
		Owner, Generator Owner, and Distribution Provider shall have evidence that it has initiated resolution of, or corrected, identified Unresolved Maintenance Issues in accordance with Requirement R5. The evidence for initiated resolution may include but is not limited to work orders for future resolution, project schedules for future resolution, or other documentation of future plans. The evidence for corrected Unresolved Maintenance Issues may include but is not limited to replacement Component orders, invoices, return material authorizations (RMAs) or purchase orders.
Response: Thank you for your comment. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the recognition that more complex unresolved maintenance issues could require more time to resolve effectively than there is time remaining in the maintenance interval, yet the problems must eventually be resolved. Measure M5 has been modified to include "project schedules with completed milestones."		
Northeast Power Coordinating Council	Yes	
DTE Energy	Yes	
MRO NSRF	Yes	
Tacoma Public Utilities	Yes	
Dominion	Yes	1. Dominion understands R3 to mean that the time-based maintenance interval can be less that but not exceed the maximum maintenance intervals in the tables. But that compliance will be based upon the maximum interval. Please confirm that our understanding is correct. 2. Dominion believes the intent of the footnote in Table 1-1 is to 'start the interval' on either the 1st day of a calendar year or calendar month. We also believe this will require any entity whose current intervals are based on annual or monthly will have to adjust their intervals to calendar as they

Organization	Yes or No	Question 2 Comment
		transition to PRC-005-2. Please confirm our understanding is correct. 3. We also believe this transition could result in the compliance interval measurement being shorter or longer than it would have been if PRC-005-2 had not been approved. If this is incorrect, please provide examples to provide clarity.
Response: Thank you for your comment. 1. Yes, your understanding of Requirement R3 is correct. 2. No, your understanding of Footnote 1 at the bottom of the page where Table 1-1 appears in the standard is not correct. The intent of Footnote 1 is to clarify, or define the terms "calendar year" and "calendar month" as they relate to the period in which the next maintenance activity for a particular interval must occur. For example, if an entity performed electromechanical relay testing at Substation A in April of 2010, in accordance with the maximum maintenance interval of six-calendar-years established in Table 1-1, the entity must perform the next round of electromechanical relay testing at Substation A sometime during the calendar-year period beginning January 1, 2016. Please see Section 7.1 of the Supplementary Reference and FAQ document for a more detailed discussion of this issue. 3. If an entity's maintenance program specifies a maintenance activity occur "30 days" from the previous activity's performance, it would be possible that a transition to a "calendar month" interval would allow the first performance of the activity after the transition to occur sooner or later than the 30 days previously specified. However, many existing maintenance programs that establish performance of an activity "annually" or "monthly" should not require more than adjusting the language in the program. For instance, if an entity's current program is to inspect substations "monthly," they are likely performing those inspections sometime during each calendar month. This practice would be no different with the interval redefined as: "once each calendar month."		
PNGC Comment Group	Yes	The PNGC comment group agrees with this change. Removing the jeopardy associated with more stringent intervals will make it less risky for entities to tighten intervals in their PSMP.
Response: Thank you for your comment and support.		

Organization	Yes or No	Question 2 Comment
ACES Power Marketing Standards Collaborators	Yes	1. We agree the changes will benefit reliability by allowing a registered entity to have shorter maintenance cycles without the potential for compliance violations associated with missing their shorter maintenance cycle. 2. Requirement R5 should be modified to focus on what is to be accomplished. As it is written now, the requirement is essentially focused on compliance by using “shall demonstrate efforts”. Compliance is about demonstrating or presenting evidence that the requirement has been met. The purpose of the requirement is to correct Unresolved Maintenance issues. We suggest changing the wording to: “shall initiate resolution of Unresolved Maintenance Issues.”
Response: 1. Thank you for your comment and support of this change. **2.** Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase “demonstrate efforts to correct” (with guidance from NERC Staff) because of the recognition that more complex unresolved maintenance issues could require more time to resolve effectively than there is time remaining in the maintenance interval, yet the problems must eventually be resolved. The SDT believes that corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of “unresolved maintenance issue” has been modified to add a clarifying phrase that the deficiency “cannot be corrected during the maintenance interval.”		
Liberty Electric Power LLC	Yes	Thank you for the change in Requirement 3. This standard now gives clear direction to entities, removes the burden of "created paperwork" intended only for the use of auditors, and removes the compliance jeopardy for holding a program to a higher standard than required.

Organization	Yes or No	Question 2 Comment
Response: Thank you for your comment and support.		
TransAlta Centralia Generation LLC	Yes	More detail explanation or examples of Efforts on R5 is required
Response: Thank you for your comment. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the recognition that more complex unresolved maintenance issues could require more time to resolve effectively than there is time remaining in the maintenance interval, yet the problems must eventually be resolved. The SDT believes that corrective actions should be timely but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "unresolved maintenance issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval." See the Supplementary Reference and FAQ document Section 4.1 for additional discussion.		
Central Lincoln		1. We thank the SDT for removing the extra compliance jeopardy associated with stringent intervals. The extra jeopardy never made sense to us, since it could result in sanctions to one entity and no sanctions to another entity when both followed the same interval with no BES risk presented by either. 2. We are concerned regarding the language of R5. We understand that maintenance without resolution is worthless, but the language here is subjective allowing different auditors to reach differing conclusions whether a sufficiently documented effort has been made. We also note that entities are expected to be continually in compliance with applicable standards, and are expected to self report when they are not. Strictly interpreted, an entity is out of compliance with R5 if there is any time lag between the moment the problem is identified in the field and documentation is produced of an effort taken to resolve it. We suggest the inclusion of a reasonable time limit.

Organization	Yes or No	Question 2 Comment
Response: 1. Thank you for your comment and support. 2. The definition of "Unresolved Maintenance Issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval," which allows the entity until the end of the maintenance interval to develop an approach for correcting the problem. See the Supplementary Reference and FAQ document Section 4.1 for additional discussion.		
Southwest Power Pool Standards Development Team	Yes	
Tennessee Valley Authority	Yes	
FirstEnergy	Yes	
Western Area Power Administration	Yes	
Pepco Holdings Inc. & Affiliates	Yes	
PacifiCorp	Yes	See comments under #4.
MRO NSRF	Yes	
Kansas City Power & Light	Yes	
Edison Mission Marketing & Trading	Yes	
Alber Corporation	Yes	
Flathead Electric Cooperative, Inc.	Yes	
Independent Electricity System Operator	Yes	
Entergy Services	Yes	
ATCO Electric Ltd	Yes	
Manitoba Hydro	Yes	
Westar Energy	Yes	
Ameren	Yes	
BAE Batteries USA	Yes	
City of Austin dba Austin Energy	Yes	

Organization	Yes or No	Question 2 Comment
BAE Batteries USA	Yes	
American Transmission Company, LLC	Yes	
CenterPoint Energy	Yes	
Duke Energy	Yes	
PNM Resources	Yes	
Los Angeles Department of Water and Power	Yes	
Response: Thank you for your support.		

3. **The Supplemental Reference and FAQ document was revised to reflect changes made to the draft standard and to address additional issues raised. Do you agree with the changes? If you do not agree, please provide specific suggestions for improvement.**

Summary Consideration: Several comments were submitted that were unrelated to this question.

Many commenters offered questions and suggestions related to the content of the Supplementary Reference and FAQ document, which resulted in assorted changes throughout the document.

Organization	Yes or No	Question 3 Comment
Fort Pierce Utilities Authority	Negative	1. The applicability of the standard should be modified to reflect the FERC approved interpretation PRC-005-1b Appendix 1 that basically says that applicable Protection Systems are those that protect a BES Element AND trip a BES Element. The applicability as currently stated will sweep in distribution protection: “4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.).” Most network distribution systems that have more than one source into a distribution network will have reverse power relays to detect faults on the BES and trip the step-down transformer to prevent feedback from the distribution to the fault on the BES. This is not a BES reliability issue, but more of a safety and distribution voltage issue. These relays would be subject to the standard as the applicability is currently written, but, should not be and they are currently not within the scope of PRC-005-1b Appendix 1 because the step-down transformer (non-BES) is tripped and not a BES Element (hence, the "and" condition of the interpretation is not met). There are many other related examples of distribution that might be networked or have distributed generation on a distribution circuit where such reverse power relays, or overcurrent relays with low pick-ups, are used for safety and distribution voltage control reasons and are not there for BES Reliability. To make matters

Organization	Yes or No	Question 3 Comment
		worse, for these Reverse Power relays, it is pretty much impossible to meet PRC-023 because the intent of the relay is to make current flow unidirectional (e.g., only towards the distribution system) without regard for the rating of the elements feeding the distribution network. So, if these relays are swept in, and if they are on elements > 200 kV, then the entity would not be able to meet PRC-023 as that standard is currently written. FPUA recommends the SDT should adopt the FERC approved interpretation. 2. Another concern is regarding the sudden pressure relays. These had been out of the scope in all previous draft versions of PRC-005-2 because these do not measure electrical quantities. However, the SDT just added a requirement to test the trip path from the sudden pressure device, arguing that it is captured by the definition of Protection Systems. This inconsistency does not make sense and could create "grey areas" for other devices that can trip for low oil level or high temperature, among others. By their nature, sudden pressure devices are far less reliable than their associated control circuitry. I know of at least one large entity that disables sudden pressure relays on smaller transformers to cut down on nuisance alarms. If it is expected that non-electrically initiated devices may become part of some maintenance standard in the future, I think it would be premature for the SDT to address sudden pressure relays in PRC-005-2. 3. And lastly, page 77 of the Supplementary Reference has some text clarifying the requirement for establishing a baseline test: "For all new installations of Valve-Regulated Lead-Acid (VRLA) batteries and Vented Lead-Acid (VLA) batteries, where trending of the cells internal ohmic measurements to a baseline are to be used to determine the ability of the station battery to perform as designed, the establishment of the baseline as described above

Organization	Yes or No	Question 3 Comment
		should be followed at the time of installation to insure the most accurate trending of the cell/unit." This guidance does not recognize the fact that some battery manufacturers recommend the baseline tests to be performed at some point in time after the install to allow the cell chemistry to stabilize after the initial freshening charge. The manual from a battery manufacturer (Enersys Powersafe) states that "The initial records are those readings taken after the battery has been in regular float service for 3 months (90 days). These should include the battery terminal float voltage and specific gravity reading of each cell corrected to 77F (25C), all cell voltages, the electrolyte level, temperature of one cell on each row of each rack, and cell-to-cell and terminal connection detail resistance readings. It is important that these readings be retained for future comparison". If an entity follows the manufacturer's recommendation, the above statements would lead an auditor to a finding of non-compliance because internal ohmic tests were not performed prior to placing a new battery string in service. A simple modification to the wording would eliminate the conflict.

Response: Thank you for your comments.

1. **The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System," and notes that this term is not used within PRC-005-2; thus, the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements.**

   To address your concern, the distribution protective devices and functions provided as examples in this comment, as pointed out by the commenter, are not "installed for the purpose of detecting Faults on BES Elements," and would, therefore, not be subject to PRC-005-2. A relay used primarily for "safety and distribution voltage control reasons" is clearly not "installed for the purpose of detecting Faults on BES Elements." The reverse power relay application described is also not "installed for

Organization	Yes or No	Question 3 Comment
the purpose of detecting Faults on BES Elements" (the relays react to changes in power flow direction, which may or may not be due to a Fault), but for the purpose of preventing feedback from the distribution system to the transmission system. Please see the PRC-005-2 Supplementary Reference and FAQ, Section 2.3, for a more detailed discussion of this issue. 2. **DC trip circuit from a sudden pressure relay output to the trip coil of the interrupting device has always been included in the "Control circuitry" portion of a Protection System, and is discussed in Section 15.3 of the PRC-005-2 Supplementary Reference and FAQ document. In regards to including sudden pressure relays themselves, FERC, in Order 758, recently directed NERC to submit an informational filing providing a schedule for addressing sudden pressure relays in PRC-005. The NERC System Protection and Control Subcommittee (SPCS) worked with NERC staff to develop the informational filing, which was filed with FERC on April 12, 2012. Activities associated with the schedule submitted in the filing will be included in a final SAR to further develop PRC-005. A draft SAR has been posted on the project page for information only.** 3. **The Drafting Team has revised the Supplemental Reference and FAQ document based on your recommendations.**		
DTE Energy	No	
MRO NSRF	No	1. Section 5.1 (second paragraph, under the first bullet) states: "TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components." If this "actual event" can be used as proof that the Protection System operated correctly, then this should be added to M3 in the Measures section of PRC-005-2. 2. Section 2.4.1 - Sudden Pressure Relays - This question should be clarified that circuits from only EHV transformers should be considered in scope. As highlighted by the NERC GMD reports EHV transformers (345, 500 & 765 kV) are critical.

Organization	Yes or No	Question 3 Comment
		3. In addition, circuits that do not actually trip a breaker (panel lights, alarms, etc.) should not be included in the scope of components included in the maintenance and testing program.
Response: Thank you for your comments. 1. **Measure M3 lists possible types of evidence, and states, "is not limited to." Therefore, in-service operations can be provided as evidence.** 2. **This standard applies to the BES and certain transformers less than 345kV are, therefore, included.** 3. **Table 5 Component Type states, "Control Circuitry associated with protective functions…" and, therefore, the circuits you reference are not included.**		
FirstEnergy	No	Please see our comments and suggested changes to the Supplemental Reference and FAQ document in Question 4.
Western Area Power Administration	No	Western Area Power Administration does not agree that the trip path from a sudden pressure device is a part of the protection system control circuitry as stated in the revised Supplementary document. FAQ should be used as guidance and not for compliance.
Response: Thank you for your comment. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1B, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff. The Supplementary Reference and FAQ document provides supporting discussion, but is not part of the Standard. 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 and FAQ document.		
Nebraska Public Power District	No	1. Section D 1.3 Evidence Retention - Do not agree with requirement to keep the two most recent performances of each distinct maintenance activity. Should

Organization	Yes or No	Question 3 Comment
		not require records previous to last audit. What is the point of keeping records up to twenty years? 2. FAQ page 7 and 77 now include discussion about how sudden pressure relays are “presently” excluded because they do not meet the definition of a protection system and a method of component verification does not exist. This part I agree with. The problem is that they go on to explain that the DC control circuitry from the Sudden Pressure relay is part of a protection system. This I disagree with. It’s clear that the Standards Drafting Team is attempting a compromise to address direction from FERC Docket No. RM10-5-000. This approach however, sets a bad precedence. A trip path from a non-protection system component should not be classified as a protection system trip path. 3. The removal of grace periods and the comments in the FAQ that it will be up to the Auditor to determine if a test was not done due to extraordinary circumstances (example: Communications can’t be tested due to the line out from a storm and under repair) is not acceptable. The SDT needs to come up with guidelines for these situations and not leave it up to each auditor to determine what is acceptable.

Response: Thank you for your comments.

1. For a Compliance Monitor to be assured of compliance, the SDT believes the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding maintenance to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT specified the data retention in the posted standard to establish this level of documentation. This seems to be consistent with the current practices of several Regional Entities.
2. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing

Organization	Yes or No	Question 3 Comment
elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff. 3. FERC Order 693 directs NERC to establish maximum allowable intervals. Grace periods would not satisfy this directive.		
PPL Supply NERC Registered Organizations	No	We recommend that the final sentence of M3 and M4 be changed to, "Any of the following constitutes sufficient evidence: dated maintenance records, dated maintenance summaries, dated check-off lists, dated inspection records, dated work orders, or other equivalent documentation," and that the slightly different final sentence of M5 be similarly changed.
Response: Thank you for your comment. The SDT believes the measures should not mandate evidence, but provide examples of evidence.		
MRO NSRF	No	1. Section 5.1 (second paragraph, under the first bullet) states: "TBM can include review of recent power system events near the particular terminal. Operating records may verify that some portion of the Protection System has operated correctly since the last test occurred. If specific protection scheme components have demonstrated correct performance within specifications, the maintenance test time clock can be reset for those components." If this "actual event" can be used as proof that the Protection System operated correctly, then this should be added to M3 in the Measures section of PRC-005-2. 2. Section 2.4.1 - Sudden Pressure Relays - This question should be clarified that circuits from only EHV transformers should be considered in scope. 3. As highlighted by the NERC GMD reports EHV transformers (345, 500 & 765 kV) are critical. In addition, circuits that do not actually trip a breaker (panel lights, alarms, etc.) should not be included in the scope of components included in the maintenance and testing program.

Organization	Yes or No	Question 3 Comment
Response: Thank you for your comments. 1. Measure M3 lists possible types of evidence and states “is not limited to.” Therefore, ‘in-service’ operations can be provided as evidence. 2. This standard applies to the BES and certain transformers less than 345kV are, therefore, included. 3. Table 5 Component Type states, “Control Circuitry associated with protective functions…” and, therefore, the circuits you reference are not included.		
Arizona Public Service Company	No	Either the FAQ or the Standard should define the bases for each interval mandated. See the response to question 2 for further details.
Response: Please see the Technical Justification document associated with Project 2007-17. Please also see Section 8.3 of the Supplementary Reference and FAQ document.		
Ingleside Cogeneration LP	No	We do not agree with the assertion in the reference and FAQs that the DC supply and control circuitry for mechanical components are part of a BES Protection System. This is not an accepted norm in the existing Standard as the Project Team claims - only an expansion in scope that was not properly vetted by the industry. If the Compliance Authorities believe that electrical components which support mechanical systems are rightfully part of the BES or BPS, then this has implications far beyond Protection System maintenance. The appropriate place to begin this determination is with Project 2010-17 Definition of the BES - where it can be fully reviewed by all affected industry stakeholders.
Response: Thank you for your comment. The trip path from a sudden pressure device is a part of the Protection System control circuitry. Sudden pressure relays, as opposed to other types of mechanical components, are installed to detect an electrical **fault** condition inside a transformer. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 3 Comment</th></tr>
<tr><td>American Electric Power</td><td>No</td><td>Though the guidance provided in these documents may appear to be beneficial, we are troubled that despite the time spent on them by the drafting team, and the voluminous nature of the references, that the information contained in them essentially fades away upon approval of the standard. Rather than voluminous supplementary references, we suggest adding this information, as necessary, to the standard itself. Not only would this prove beneficial by having less information housed outside of the standard, it might help prevent the need for future CANs and interpretation requests.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

The Supplementary Reference and FAQ document provides supporting discussion, but is not part of the standard. 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 and FAQ document. The Supplementary Reference will be revised in the course of the revision process of the standard.</td></tr>
<tr><td>Westar Energy</td><td>No</td><td>1. We believe all of the 4 month intervals can be changed to 6 month intervals and still ensure reliability. It is unclear which equipment Table 1-4(d) applies to.
2. In the heading it says “Excluding distributed UFLS and distributed UVLS”, then the line below that says “non-distributed UFLS system, or non-distributed UVLS systems is excluded”.</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.

1. The activity related to this interval is to verify various basic operating parameters. The SDT believes that extension of verification of these parameters beyond the interval within the standard is inappropriate.
2. These are addressing two different items; the first addresses distributed UFLS/UVLS, whether tripping at BES levels or not, and the second addresses non-distributed UFLS/UFLS/SPS that trips only non-BES interrupting devices.</td></tr>
<tr><td>Ameren</td><td>No</td><td>We agree with the intent of the Supplement changes but believe that they are either incomplete or need clarification. Therefore, we provide the specifics as</td></tr>
</table>

Organization	Yes or No	Question 3 Comment
		follow : (a) Page 93, Revise Section 15.7 Distributed UFLS (i) Change Table 1-2 to 1-3.(ii) Include ‘Verify operation...and/or auxiliary tripping device’ to agree with Table 3. (b) Please identify BES Elements in Supplementary Reference Figure 2. (c) Remove ‘Reverse power relays’ from the bulleted list on the top section of page 33. They provide thermal of the steam turbine, and they may protect CTG speed reduction gear teeth, but neither of these are electrical protection of the generator. (d) Please add Interval FAQ to address a component minimum maintenance activity that is not in the present PRC-005-1 program. (i) : “How is interval proven for a component minimum maintenance activity that is not in the present PRC-005-1 program? For example, suppose the present program continuously monitors a communication system, say audio tones, and personnel respond to alarms; this approach presently have basis that is sufficient. (ii) Table 1-2 requires two maintenance activities every 12 calendar years: 1) verify channel meets performance criteria; and 2) verify essential I/O. The entity is required to perform these minimum maintenance activities one time in the first 13 years after regulatory approval. The 12 year interval is proven by the date of the PRC-005-2 maintenance activity and the date of your PRC-005-1 program applicable for the previous maintenance. After the second time the PRC-005-2 maintenance activity is performed, appropriately sometime in year 14 to 25 after regulatory approval, then interval will be proven by the dates of the two PRC-005-2 maintenance activities.” (e) Page 17 We disagree with retention of maintenance records for replaced equipment as this can cause confusion. At most the last maintenance date could be retained to prove interval between it and the test date of the replacement

Organization	Yes or No	Question 3 Comment
		equipment that provides like-kind protection. (f)Page 36, FAQ 'initial date for maintenance' answer is inconsistent with CAN-0011. Though the CAN applies to PRC-005-1, it should be consistent with NERC's position on this. (g) Page 71, Please remove 'The trip path from a sudden pressure device is a part of the Protection System control circuitry...' because the actuating relay does not respond to electrical quantities. This is just one example of the many gotcha's that will no doubt arise in enforcement. (h) If a capacitor trip device is an example of a non-battery based station DC supply, then please provide a FAQ to convey it.

Response: Thank you for your comments.

a. The SDT modified the Supplementary Reference and FAQ document, as suggested.

b. The applicable facilities for a generator are listed in Section 4.2.5 of the standard. Figure 2 is a visual representation of this.

c. Reverse power relays, as discussed in your comment, do not detect Faults; but if they can trip the generator, they must be maintained per 4.2.5.

d. This issue is addressed in the Implementation Plan for Project 2007-17.

e. The records for removed/replaced equipment need to be retained to provide documentation that you were in compliance for the entire compliance monitoring period.

f. The SDT has provided guidance as it relates to PRC-005-2.

g. The trip path from a sudden pressure device is a part of the Protection System control circuitry. The sensing element is omitted from PRC-005-2 testing requirements because the SDT is unaware of industry recognized testing protocol for the sensing elements. The SDT believes that Protection Systems that trip (or can trip) the BES should be included. This position is consistent with the currently-approved PRC-005-1b, consistent with the SAR for Project 2007-17, and understands this to be consistent with the position of FERC staff.

Organization	Yes or No	Question 3 Comment
h. If the "capacitor trip device" you reference is the stored energy device for the breaker, it would not be included in Table 1-4(d).		
Central Lincoln	No	The Supplemental Reference and FAQ apparently has not kept up with definition changes and uses uncapitalized "component" "Protection System components". Please use capitals if defined terms are intended.
Response: Thank you for your comment. The SDT modified the Supplementary Reference and FAQ document as suggested.		
BAE Batteries USA	No	Page 20 states that every 18 months "battery ohmic values to station battery baseline (if performance tests are not opted)" should be changed to add comment that ohmic values, while permissible as a tool, should not be taken to validate the actual capacity, thus the reliability of the battery. If capacity is an issue due to questionable ohmic values shown, a decision must be made to [1] perform a capacity test following one of the three methodologies recorded in IEEE 450 or IEEE 1188; [2] make a decision to replace the battery string depending upon the number of cells with questionable ohmic values shown, the age of the battery string, and the critical nature of the station in question; or [3] accept the risk that the battery may or may not perform as intended due to the lack of a true knowledge of the battery capacity (See IEEE Letter to Al McMeekin). Every 18 calendar months verify/inspect the following: "Cell Condition of all individual battery cells (where visible) should add "or as frequently as recommended in the battery manufacturer's operating instructions."Every 6 years: perform or verify the following:"Battery Performance Test (if internal ohmic tests are not opted)" should be changed to read "Battery Performance Test (if ohmic tests are not conducted or if ohmic test values show that a degraded situation with the cells call into question whether the battery will perform to "design requirements."this should be repeated where referenced in additional examples (VLA, VRLA, Ni-Cd)
Response: Thank you for your comment. The drafting team agrees with your statement, and those of others concerning the true capacity of the station battery and relating it to internal ohmic measurements. Tables 1-4a, 1-4b and 1-4c have been modified for clarity, and the Supplemental Reference and FAQ document has been modified to further elaborate on these concerns.		
ExxonMobil Research and	No	: As written, the current draft of PRC-005-2 discriminates against smaller entities

Organization	Yes or No	Question 3 Comment
Engineering		that do not have a population size of 60 for each component type. Historical records provide an accurate account of how specific components have performed in their installed environment. For a set population size, increasing the number of historical data points should improve the accuracy of an entity's calculated mean time between failures, so, if you increase the period over which the historical data must be evaluated, you can compensate for a smaller segment population size. The SDT's current draft prevents smaller entities from using a larger historical data set to make up for a smaller population size when developing a performance based protective system maintenance and testing program. The SDT should reconsider allowing smaller entities to use historical records that extend for period longer than a single year in the development of a performance based program.
Response: Thank you for your comment. Small entities are permitted to aggregate their components with similar components of other entities to meet the component populations, as long as the programs are (and remain) similar – See Section 9 of the Supplementary Reference and FAQ document and the associated footnote to Attachment A. Decreasing the component population below the requirements of Attachment A will result in an unsound program due to component populations that are not statistically significant. The Supplementary Reference and FAQ document states, "Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM but does not own 60 units to comprise a population then that asset owner may combine data from other asset owners until the needed 60 units is aggregated." Historical data may be good for trending, but may not be suitable for judging current maintenance program effectiveness.		
TransAlta Centralia Generation LLC	Yes	More detail explanation on Segment is required; the reason of sixty (60) individual components is required for one Segment. More detail explanation on Countable Event is required.
Response: Thank you for your comments. The SDT believes that Segment and Countable Events are clearly stated in the standard. Decreasing the component population below the requirements of Attachment A will result in an unsound program due to component populations that are not statistically significant.		
City of Austin dba Austin Energy	Yes	The effort expended by the SDT in creating and revising the content of the

Organization	Yes or No	Question 3 Comment
		Supplemental Reference and FAQ is admirable and most appreciated. The guide is a useful reference.
Response: Thank you for your comment and support.		
Los Angeles Department of Water and Power	Yes	LADWP notices that the terms "Unresolved Maintenance Issue" and "maintenance-correctable issue" are used in several places. We recognize that "Unresolved Maintenance Issue" is defined as a deficiency identified during a maintenance activity that causes the component to not meet the intended performance and requires follow-up corrective action. Please define "maintenance-correctable issue" and clarify the differences between the two terms.
Response: Thank you for your comments. “Unresolved Maintenance Issue” replaced the term “maintenance-correctable issue,” and the SDT corrected the Supplementary Reference and FAQ document to reflect the change.		
Progress Energy		1. Table 3, Row 7: The requirement to “Verify electrical operation of electromechanical lockout and/or tripping auxiliary devices” contradicts Section 15.7, bullet 2 of the Supplementary Reference and FAQ document. In the supplementary reference, the phrase “and/or auxiliary tripping device(s)” has been struck out.
Response: Thank you for your comments. The Supplementary Reference and FAQ document has been modified per your suggestion.		
EPRI	No	see comments in question 1
Northeast Power Coordinating Council	Yes	
Tacoma Public Utilities	Yes	
Imperial Irrigation District (IID)	Yes	
Southwest Power Pool Standards Development Team	Yes	

Organization	Yes or No	Question 3 Comment
Tennessee Valley Authority	Yes	
PNGC Comment Group	Yes	
Bonneville Power Administration	Yes	
ACES Power Marketing Standards Collaborators	Yes	
Southern Company Generation	Yes	
Kansas City Power & Light	Yes	
Edison Mission Marketing & Trading	Yes	
Alber Corporation	Yes	
Independent Electricity System Operator	Yes	
Liberty Electric Power LLC	Yes	
Entergy Services	Yes	
ATCO Electric Ltd	Yes	
Manitoba Hydro	Yes	
US Bureau of Reclamation	Yes	
American Transmission Company, LLC	Yes	
CenterPoint Energy	Yes	
Xcel Energy	Yes	
Duke Energy	Yes	
PNM Resources	Yes	
Response: Thank you for your support.		

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

Summary Consideration: Several comments were repeated from Questions 1, 2, or 3, and the summary consideration responses are not repeated here.

Numerous commenters suggested minor changes to the definition of the terms "inspect" and "Countable Event." In response, the SDT modified the description of the term, "inspect" within the definition of PSMP. Previously "inspect" was "Examine for signs of component failure, reduced performance or degradation." now "inspect" is "Examine for signs of component failure, reduced performance or degradation." The SDT also modified the definition of Countable Event from "A Component which has failed and requires repair or replacement…" to "A failure of a Component requiring repair or replacement …"

The SDT continued to receive comments regarding the Applicability of the standard. The SDT modified the Applicability Clause 4.2.5.4 to read: "Protection Systems for station service or excitation transformers connected to the generator bus of generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays."

Some commenters questioned the last line in Table 1-2 for Communications Systems. The SDT realized they had several errors in the table – one omitted element and one incorrect interval. The table was corrected.

Several comments were offered regarding the station battery activities in Tables 1-4 (a-f). Representatives of the IEEE Stationary Battery Committee assisted the SDT in making revisions to these tables to address concerns related to ohmic testing of the cell/units.

Several commenters questioned elements of the criteria in Attachment A for performance-based maintenance; the SDT explained the rationale for these criteria, including, where appropriate, the related statistical basis.

Several comments pointed out inconsistencies between the Standard and Supplementary Reference and FAQ. The SDT modified the Standard and Supplementary Reference and FAQ to address these inconsistencies.

A few commenters questioned portions of the standard, or suggested changes that the SDT chose not to adopt. The SDT responded with their rationale. These comments included:

- **NERC should provide a format for test reports, etc.**
- **Include batteries within a performance-based PSMP**
- **Objections to the inclusion of distribution devices that are installed for the benefit of the BES**

- **VSLs permitting entities to experience some small level of non-performance relative to the standard without incurring a violation**
- **VSLs set at inappropriate levels**
- **The inclusion of the control circuitry related to sudden pressure relays, even though sudden pressure relays themselves are not included**
- **Various facets of control circuitry maintenance**
- **Specific intervals or activities within the tables**
- **Evidence retention language**
- **Intervals for lockout relays**
- **Voltage and current sensing devices**

Organization	Yes or No	Question 4 Comment
Northern Indiana Public Service Co.	Negative	A format for maintenance reports and specific test requirements for relays are missing.
Response: Thank you for your comments. The SDT does not believe it is necessary or appropriate to prescribe a specific format for maintenance results or test requirements.		
James A Maenner	Negative	As written, the standard may require DPs to include distribution protection devices designed to isolate and protect distribution facilities from faults on monitored transmission or other BES facilities. Qualifying language should be added differentiate protective systems which control BES and distribution facilities for faults on the BES.
Response: Thank you for your comments. PRC-005-2 specifically addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements, even if they are installed on distribution facilities. UFLS and UVLS devices which are commonly installed on distribution facilities for the purposes of addressing related NERC Standards are included. Protection Systems installed on distribution facilities for the purposes of detecting Faults on distribution facilities are not included.		
SERC Reliability Corporation	Negative	FERC Order 758 includes directives that affect this project. I understand that the

Organization	Yes or No	Question 4 Comment
		SPCS/SAMS group is looking at the technical documents to support additional standards activity but as this project is presented, it does not meet the FERC directives. Otherwise, I could vote affirmatively, but I do have some concerns about how clearly and unambiguously the standards requirements are written. This standard should be a candidate for the RSAW initiative being developed by the Standards Committee.
Response: Thank you for your comments. The Standards Committee has directed the PSMTSDT to finalize PRC-005-2 and present it to the NERC Board of Trustees for adoption, and concurrent with this posting of PRC-005-2 to post for information a draft SAR for a second phase of Project 2007-17 addressing further modifications to PRC-005-2. FERC Order 758 includes directives associated with Maintenance and Testing of Auxiliary and Non-Electrical Sensing Relays, Reclosing Relays, and DC Control Circuitry. Regarding these directives in relation to PRC-005-2: 1. Testing of Auxiliary and Non-Electrical Sensing Relays – The NERC System Protection and Control Subcommittee (SPCS) recently worked with NERC staff to develop an informational filing in response to Order 758. Activities associated with the schedule submitted in the filing will be included in a final SAR to establish a future phase of Project 2007-17 for future development of PRC-005. A draft SAR is posted on the project page for information only. 2. Reclosing relays will be addressed in a second phase of this project, which will produce PRC-005-3. Development of that revision will begin after PRC-005-2 is completed and the NERC SPCS completes the technical documentation regarding reclosing relays. 3. DC Control Circuitry and Components – This draft standard PRC-005-2 includes extensive, specific maintenance activities (with maximum maintenance intervals) related to the DC control circuits.		
Southwest Transmission Cooperative, Inc.	Negative	1. For the Requirement R1's High VSL, "entities'" should be "entity's" to be consistent with the other VSLs. 2. It is not clear why missing three component types jumps to a Severe VSL. Missing two is a Moderate VSL. Missing three should be a High VSL.
Response: Thank you for your comments.		

Organization	Yes or No	Question 4 Comment
1. The SDT has corrected the Requirement R1 VSL, as you suggest. 2. The SDT believes that missing three components is considered a "significant percentage," and is in accordance with the VSL guidelines.		
Midwest ISO, Inc.	Negative	In the VSL for Table 4 it seems that the phrase "5% or less" should be "not more than 5%". With the original language it seems like an entity could be found to have an R4 lower VSL violation for "failure" of zero meaning they had done no testing. This VSL is written in the negative and should be rewritten in the positive.
Response: Thank you for your comments. The VSL Guidelines, developed in accordance with FERC's VSL Order, establish the Lower VSL for stepped VSLs as "5% or less," the Medium VSL as "more than 5% but less than (or equal to) 10%," the High VSL as "more than 10% up to (and including) 15%," and the Severe VSL as "more than 15%."		
Lincoln Electric System	Negative	Please refer to comments submitted by the MRO NERC Standards Review Forum for LES' concerns related to PRC-005-2.
Western Area Power Administration	Negative	Please see comments provided on Official Comment Form
Minnkota Power Cooperative, Inc.	Negative	
Lakeland Electric	Negative	Please see FMPA comments
Kissimmee Utility Authority	Negative	Please see separately submitted FMPA comments.
Baltimore Gas & Electric Company	Negative	Please see the issues raised in the Comment Form submitted on behalf of Constellation.
Occidental Chemical	Negative	See comments submitted by Ingleside Cogeneration LP
Dairyland Power Coop.	Negative	See MRO NSRF comments.
U.S. Army Corps of Engineers	Negative	See MRO/NSRF comments
Dairyland Power Coop.	Negative	See NSRF comments.
Beaches Energy Services	Negative	The applicability of the standard should be modified to reflect the FERC approved interpretation PRC-005-1b Appendix 1 that basically says that applicable Protection Systems are those that protect a BES Element AND trip a BES Element. The

Organization	Yes or No	Question 4 Comment
		interpretation states: The applicability as currently stated will sweep in distribution protection: "4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)" Many (most) network distribution systems that have more than one source into a distribution network will have reverse power relays to detect faults on the BES and trip the step-down transformer to prevent feedback from the distribution to the fault on the BES. This is not a BES reliability issue, but more of a safety issue and distribution voltage issue. These relays would be subject to the standard as the applicability is currently written, but, should not be and they are currently not within the scope of PRC-005-1b Appendix 1 because the step-down transformer (non-BES) is tripped and not a BES Element (hence, the "and" condition of the interpretation is not met). There are many other related examples of distribution that might be networked or have distributed generation on a distribution circuit where such reverse power relays, or overcurrent relays with low pick-ups, are used for safety and distribution voltage control reasons and are not there for BES Reliability. To make matters worse, for these Reverse Power relays, it is pretty much impossible to meet PRC-023 because the intent of the relay is to make current flow unidirectional (e.g., only towards the distribution system) without regard for the rating of the elements feeding the distribution network. So, if these relays are swept in, and if they are on elements > 200 kV, then the entity would not be able to meet PRC-023 as that standard is currently written. So, the SDT should adopt the FERC approved interpretation.

Response: Thank you for your comments.

The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection **System**," and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses Protection Systems that are installed for the purpose of detecting Faults on BES Elements.

To address your concern, the distribution protective devices and functions cited in this comment are not "installed for the purpose of detecting Faults on BES Elements," and would, therefore, not be subject to PRC-005-2. A relay used primarily for "safety and distribution voltage control reasons" is clearly not "installed for the purpose of detecting Faults on BES Elements." The reverse

Organization	Yes or No	Question 4 Comment
power relay application described is also not “installed for the purpose of detecting Faults on BES Elements” (the relays react to changes in power flow direction, which may or may not be due to a Fault) but for the purpose of preventing feedback from the distribution system to the transmission system. Please see the PRC-005-2 Supplementary Reference and FAQ, Section 2.3, for a more detailed discussion of this issue.		
U.S. Bureau of Reclamation	Negative	1. The definition for PSMP is incongruous with the use of the PSMP in Requirement R1. Requirement R1, including the Measure and VSL focus on the identification of maintenance method of the Component types and not that the PSMP is in fact being used for maintenance of the component. 2. The requirement R5 indicates the entity has to "demonstrate" efforts to correct identified unresolved maintenance issues. The measure M5 described documentation of the efforts. The requirement language should be explicit. Does the standard want a demonstration which implies active role of the entity to prove what it is doing, or to provide documentation of the activities underway to correct deficiencies? The language in the requirement should be altered to "Each Transmission Owner, Generator Owner, and Distribution Provider shall prepare a CAP for each identified Unresolved Maintenance Issue." A second requirement is needed to require that "Each Transmission Owner, Generator Owner, and Distribution Provider shall complete its CAP to correct the identified Unresolved Maintenance Issues." The measures would need to be adjusted accordingly to reflect the CAP and evidence that the entity completed the CAP. 3. Re Terms defined for use only within PRC-005-2: The standard provides definitions which will not be incorporated into the Glossary of Terms. This would allow the definitions as used in this standard to conflict with the definition used in other standards if this practice becomes more widespread and would reduce the cohesiveness of the standard set. 4. Re The definition of Components: The standard defined what constitutes a

Organization	Yes or No	Question 4 Comment
		control circuit as a component type with "Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices." The standard then modified the definition by allowing "a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry." The definition should not be dependent upon practice. This makes the definition a fill in the blank definition. Either eliminate the allowance or remove the definition of control circuit.

Response: Thank you for your comments.

1. The SDT believes that the definition of a PSMP is linked to Requirement R1 in that the entity's program shall include one or all of the parameters in the definition. Requirement R1 requires that the entity establish their program and is the foundation for the standard. Requirements R3-R4 address implementation of the entity's PSMP.
2. The term within Requirement R5, "… demonstrate efforts …" is intended for both – that the entities are acting to correct the deficiency and also (to prove compliance) maintaining documentation of the activities underway to correct the deficiency. The SDT elected to not require a "Corrective Action Plan," as defined in the NERC Glossary of Terms, to avoid much of the systemic, ongoing documentation attendant to that term. However, if an entity wishes to use a Corrective Action Plan as defined, that would be an acceptable method of meeting Requirement R5.
3. The standard specifies that the terms used are intended for this document only; and, therefore, there should not be any conflict with their use in any other PRC standard.
4. The intent of the different means of identifying control circuitry was to accommodate various entities' philosophies on testing of these circuits. Regardless of how an entity chooses to identify their control circuitry, the entity must meet the requirements of the standard regarding maintenance of control circuitry.

Organization	Yes or No	Question 4 Comment
Independent Electricity System Operator	Negative	The IESO continues to disagree with the VRF assigned to the new Requirements R3 and R4. R3 and R4 ask 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/R4 not executable. Hence, we reiterate our position that the VRF for R3 be changed to Medium.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. The SDT team disagrees and believes the failure to implement a PSMP should be assigned a VRF of High.		
Illinois Municipal Electric Agency	Negative	The inconsistency between the proposed Protection System language in the Applicability section of PRC-005-2 and the transmission Protection System interpretation recently approved by FERC (PRC-005-1b Appendix 1) needs to be resolved.
Response: The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term “transmission Protection System,” and notes that this term is not used within PRC-005-2; thus, the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses “Protection Systems that are installed for the purpose of detecting Faults on BES Elements.” Please see Section 2.3 of the Supplementary Reference Document for additional discussion.		
Central Lincoln PUD	Negative	The percentage based VSL unreasonably penalizes smaller entities, since one Component can cause them to hit the 10% cutoff for a High VSL while a large entity may miss 100s of components without exceeding the Lower VSL.
Response: Thank you for your comments. A smaller entity will have less to maintain in accordance with the standard; and, thus, the percentages are still appropriate.		
JEA	Negative	This standard greatly expands the scope of work that will be required of JEA without providing a corresponding incremental increase in reliability and may in fact cause reliability issues. Specific concerns are that JEA believes that we do continuous monitoring of a vast majority of our components and our approach has demonstrated its effectiveness but the revised standard will most likely require JEA to have to adopt a new approach with significant increases in manpower hours. Additionally, testing lockouts is of great concern because of its ability to cause reliability issues.
Response: Thank you for your comments. The SDT believes that performing these maintenance activities will benefit the reliability of the BES. If your components are monitored according to the attributes specified in Table 1-1 through 1-5, you may be able to utilize the extended intervals/minimized		

Organization	Yes or No	Question 4 Comment
activities associated with those monitoring attributes within the tables. The SDT believes that electromechanical lockout relays need periodic operation. As such, these devices are required to be exercised at the same six-year interval required for electromechanical relays. The SDT recognizes the risk of 'human error' trips when testing lockout devices, but believes these risks can be managed. Performance-based maintenance is an option if you want to extend your intervals beyond six years.		
City and County of San Francisco	Negative	VSL's are based upon Failure to Maintain Percentages for "a specific Protection System component type". VSL's should be based upon Failure to Maintain Percentages for total number of Protection System components, and not give greater weight in the VSL determination, to component types with few elements, like station batteries.
Response: Thank you for your comments. The SDT believes that these VSLs should address failures to maintain percentages of each Component Type. Failure to maintain quantities of low-population Component Types, such as station batteries, may have serious consequences for BES reliability, and the SDT believes that these must not be masked by larger populations of other Component Types, such as protective relays.		
Gainesville Regional Utilities	Negative	We support FMPA's position on this matter.
Response: Thank you for your comments. Please see our response to FMPA's comments.		
Blachly-Lane Electric Co-op	Affirmative	Please see "PNGC Comment Group" for our comments.
Georgia Power Company	Affirmative	Refer to Comments submitted by Antonio Grayson.
Georgia Transmission Corp.	Affirmative	
Western Electricity Coordinating Council	Affirmative	
SMUD	Affirmative	
Western Farmers Electric Cooperative	Affirmative	
Central Electric Cooperative, Inc. (Redmond, Oregon)	Affirmative	Please see "PNGC Comment Group" for our comments.
Clearwater Power Co.	Affirmative	Please see "PNGC Comment Group" for our comments.
Consumers Power Inc.	Affirmative	Please see "PNGC Comment Group" for our comments.

Organization	Yes or No	Question 4 Comment
Coos-Curry Electric Cooperative, Inc	Affirmative	Please see "PNGC Comment Group" for our comments.
Fall River Rural Electric Cooperative	Affirmative	Please see "PNGC Comment Group" for our comments.
Lane Electric Cooperative, Inc.	Affirmative	Please see "PNGC Comment Group" for our comments.
Northern Lights Inc.	Affirmative	Please see "PNGC Comment Group" for our comments.
Pacific Northwest Generating Cooperative	Affirmative	Please see "PNGC Comment Group" for our comments.
Raft River Rural Electric Cooperative	Affirmative	Please see "PNGC Comment Group" for our comments.
Umatilla Electric Cooperative	Affirmative	Please see "PNGC Comment Group" for our comments.
West Oregon Electric Cooperative, Inc.	Affirmative	Please see "PNGC Comment Group" for our comments.
Ohio Edison Company	Affirmative	Please see FirstEnergy's comments submitted through the formal comment period.
MidAmerican Energy Co.	Affirmative	Please see MidAmerican and MRO NSRF Comments.
Madison Gas and Electric Co.	Affirmative	Please see MRO NSRF comments
Great River Energy	Affirmative	Please see MRO NSRF comments.
Omaha Public Power District	Affirmative	Please see MRO NSRF Comments.
Muscatine Power & Water	Affirmative	Please see the comments submitted by MRO NSRF
North Carolina Electric Membership Corp.	Affirmative	Please see the formal comments submitted by ACES Power Marketing.
Midwest ISO, Inc.	Affirmative	See Comments submitted by the MRO NSRF.
MidAmerican Energy Co.	Affirmative	See MidAmerican and NSRF comments
Southwest Transmission Cooperative, Inc.	Affirmative	1. The first part of definition of a Countable Event should be modified as follows: “The failure of a Component such that it requires repair or replacement...”. As it is currently word, it is technically counting the Component as the Countable Event and not the failure of the component. Considering that the other two items that are Countable Events are conditions and misoperations, it seems appropriate to

Organization	Yes or No	Question 4 Comment
		make failure the Countable Event. 2. Application of this standard to UFLS is problematic as worded in Section 4.2.2. The UFLS are only applicable if “installed per ERO underfrequency load-shedding requirements”. Technically, no UFLS fits this description because there are no ERO requirements to have a UFLS. PRC-006-0 was never approved by the Commission and is not enforceable. The Commission considered it a “fill-in-the-blank” standard. While PRC-006-1 corrects the “fill-in-the-blank” issues and was approved by the NERC BOT November 4, 2010, the Commission has yet to act on it. 3. The data retention requirement for the Protection System Maintenance Program documentation seems excessive. The Data Retention section states that all versions since the last compliance audit must be maintained. Since TOs, GOs, and DPs are all on six year audit cycles, this would require maintaining this documentation for six years. Is this really necessary? The length could become even greater once NERC implements registered entity assessments that could shorten or lengthen the periods between compliance audits. The data retention requirements for Requirements R2, R3, R4, and R5 are not consistent with NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C - Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. The data retention requirements compel the registered entity to retain documentation for the longer of “the two most recent performances of each distinct maintenance activity for Protection System Components, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date”. While it may have been intended to apply to both clauses, the “since the previous schedule audit date”

Organization	Yes or No	Question 4 Comment
		only applies to the second clause. Since some of the maintenance activities have intervals of 12 years, this would require the registered entity to retain documentation for 24 years which cannot be audited since it is outside the audit window per the Rules of Procedures. At a minimum, we suggest clarifying that the documentation must not be maintained past the day after the last audit completion date. 4. In the fourth paragraph of the Data Retention section, Component is not used consistently. It is used in both singular and plural form. It seems like it should be one or the other. 5. Requirement R1 VSLs: For the High VSL, “entities’” should be “entity’s” to be consistent with the other VSLs. 6. It is not clear why missing three component types jumps to a Severe VSL. Missing two is a Moderate VSL. Missing three should be a High VSL.

Response: Thank you for your comments.

1. The SDT agrees with your comments on Countable Event, and has modified the definition of Countable Event to: “A failure of a Component requiring …”
2. Applicability Clause 4.2.2 applies to whatever ERO-required UFLS that may exist, either today or in the future. NERC Reliability Standard PRC-006-1 has now been approved by FERC.
3. The SDT believes that all versions of the entity’s PSMP should be retained for audit purposes. For a Compliance Monitor to be assured of compliance, the SDT believes the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding maintenance to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted standard to establish this level of documentation.
4. The SDT has corrected the fourth paragraph of the Evidence Retention section as you suggested.
5. The SDT has corrected the Requirement R1- High VSL, as you suggested.
6. The SDT believes that missing three components is considered a “significant percentage,” and is in accordance with the VSL

Organization	Yes or No	Question 4 Comment
Guidelines.		
Oncor Electric Delivery	Affirmative	The proposed consolidation of these standards (PRC-005-1, PRC-008-0, PRC-11-0 and PRC-017-0) provides more clarity and less room for varying interpretations for relay maintenance and testing.
Response: The SDT thanks you for your comment and affirmative vote.		
Southern Company Generation		For the 18 month / 6 year activities, it is technically incorrect to allow equivalency between internal ohmic measurements and performance testing. This view is not substantiated by industry experience, documentation, or standards. Additionally, it should be specified to the auditor that the intervals for the battery maintenance are relevant to the component, not the application. This means that if a battery is replaced just before a required 6 year performance test, the 6 year interval for the performance test is reset.
Response: Thank you for your comment. The drafting team agrees with your statement, and those of others concerning the true capacity of the station battery and relating it to internal ohmic measurements. Tables 1-4a, 1-4b and 1-4c have been modified for clarity, and the Supplemental Reference and FAQ document will be modified to further elaborate on these concerns. The SDT agrees with your assessment that the maintenance activity is relevant to the component, not the application. Guidance to the auditors of this nature is beyond the ability of the SDT. See Section 4.1 of the Supplementary Reference and FAQ document for additional discussion on this topic.		
Ameren		(a) R3 & R4: Change VRF to "Medium" for the following reasons: (i) Consistency with existing standards that PRC-005-2 replaces. Per the VRF_Standards_Applicability_Matrix_2012-03-01, PRC-005-1b R2 VRF is Lower, PRC-008-0 R2 VRF is Medium, PRC-011-0 R2 VRF is Lower, and PRC-017-0 R2 VRF is Lower. (ii) We are not aware that lack of Protection System maintenance alone has directly caused or contributed to bulk electric system instability, separation, or a cascading sequence of failures. (iii) Many entities do not presently perform several of the proposed minimum maintenance activities, and/or perform maintenance activities at greater than the PRC-005-2 maximum interval. Yet BES system instability, separation, or cascading sequence of failure events are extremely rare. (iv) Either change VRF to

Organization	Yes or No	Question 4 Comment
		Medium, or double the percentage ranges applied to each component type across VSLs. We strongly believe that the SDT needs to retune these to match the experienced risk, which has been extremely low. (b) Measure M3 on page 6 should only apply to 99.5% of the components. Please revise to state: “Each ... shall have evidence that it has implemented the Protection System Maintenance Program for 99.5% of its components and initiated....” We believe that PRC-005-2 unrealistically mandates perfection without providing technical justification. A basic premise of engineering is to allow for reasonable tolerances, even Six Sigma allows for defects. Requiring perfection may well harm reliability by distracting valuable resources from higher priority duties concerning the Protection System. We are not asking for the VSL to be changed. The consequence of a very small number of components having a missed or late maintenance activity is insignificant to BES reliability. Our proposed reasonable tolerance sets an appropriate level of performance expectation. We disagree with the notion that this is “non-performance”. (c) Measure M5 - add ‘internal inventory / parts request, trouble investigation assignment, trouble repair report’ as examples of an entity undertaking efforts with internal parts and/or labor resources. (d) Augment R3 and R4 VSL with a ‘number based limit for populations up to 100 components’ for comparable treatment of small entities. For example, for Lower VSL restate as ‘...the responsible entity failed to maintain from one to five Components if total Components is less than 100; or 5% or less of the total Components if total exceeds 99 included within a specific Protection System Component Type...’. Otherwise a small entity could unfairly incur a Severe violation for the same number of Components that a larger entity would incur a Lower VSL. (i) Similarly, Moderate numbers should be 6 to 10; High 11 to 15; and Severe 16 or more if the total Components of a certain Component Type that is less than 100. (e) Augment R5 VSL with percentage based limits for comparable treatment of larger entities. For example, for Lower VSL restate as ‘The responsible entity failed to undertake efforts to correct 5 or less Unresolved Maintenance Issues if total of such issues in the audit period is less than 100; or 5% or less if total of such issues in the

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td></td><td></td><td>audit period exceeds 99.’ (i) Similarly, Moderate numbers should be >5% to 10%; High >10% to 15%; and Severe more than 15% if the total Unresolved Maintenance Issues in the audit period exceeds 99.
(f) Please number all pages of the standard. They are missing from pages with tables.
(g) Please add a title to the table following Table 3. Is it a continuation of Table 3?</td></tr>
<tr><td colspan="3">Response: Thank you for your comments.
a) The SDT disagrees, and believes a VRF of High is appropriate for Requirements R3 and R4.
b) NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation.
c) The SDT agrees that the examples listed would constitute evidence of undertaking efforts to correct Unresolved Maintenance Issues; however, Measure M5, as written, includes the phrase, “… includes but is not limited to …” to emphasize that entities may use other evidence.
d) The SDT disagrees and believes a smaller entity will have less to maintain in accordance with the standard; and, thus, the percentages are still appropriate.
e) The SDT disagrees and believes the VSL’s for Unresolved Maintenance Issues should be a numeric quantity and not a percentage.
In response to each of the comments ‘a’ through ‘e’, the SDT recommends reviewing the “VRF/VSL Justification” that is posted with the standard. This document provides the SDT’s analysis of how the VRFs and VSLs meet FERC and NERC guidelines, as required for the standard to achieve regulatory approval.
f) The SDT numbered all the pages.
g) The SDT corrected the Table 3 header issue.</td></tr>
<tr><td>Sacramento Municipal Utility District</td><td></td><td>1) SMUD wishes to comment on the requirement to test the trip paths from relays that do not respond to electrical quantities. In two separate sections of the FAQ, the SDT included this new guidance on the trip paths. In section 2.4.1 of the FAQ, the SDT plainly asserts that the trip path from Sudden Pressure Relays (SPR) will now be covered and implies that the trip paths from non-electrically initiated devices might also be covered. In section 2.4.1, the SDT does not provide any guidance on how to determine which trip paths are included, but does provide guidance on how one might test the trip path. In section 15.3, the SDT finally provides the guidance -</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		control circuits (trip paths) are included if the relay is installed to detect faults on BES Elements. In reviewing the definition of Protection System, SMUD feels the “Control circuitry associated with protective functions...” to be in reference to the “Protective relays which respond to electrical quantities”. The SDT is now applying a new interpretation in which each of the five bullets is considered separately. Furthermore, the SDT appears to be defining “...associated with protective functions...” to mean detecting faults on the BES. What basis can the SDT offer for defining this phrase to mean detecting faults on the BES? Since this same wording is not used in defining the relay, can a relay be covered under the standard, but not its control circuitry? For instance, Out of Step Tripping? Over Excitation? Frequency or Voltage Protection on a generator? These relays respond to electrical quantities, but are not applied to detect faults on BES Elements. SMUD believes this interpretation takes us down a very confusing path. SMUD respectively requests the SDT strike the new wording (as seen on the redlined version) in 2.4.1 and 15.3.

Response: Thank you for your comments.

1. DC trip circuit from a sudden pressure relay output to the trip coil of the interrupting device has always been included in the “Control circuitry” portion of a Protection System, and is discussed in Section 15.3 of the PRC-005-2 Supplementary Reference and FAQ document. In regards to including sudden pressure relays themselves, FERC, in Order 758, recently directed NERC to submit an informational filing providing a schedule for addressing sudden pressure relays in PRC-005. The NERC System Protection and Control Subcommittee (SPCS) worked with NERC staff to develop the informational filing, which was filed with FERC on April 12, 2012. The Standards Committee has directed the PSMTSDT to finalize PRC-005-2 and present it to the NERC Board of Trustees for adoption, and concurrent with this posting of PRC_005-2, to post for information a draft SAR for a second phase of Project 2007-17 addressing further modifications to PRC-005-2.

Activities associated with the schedule submitted in the filing will be included in the final SAR to further develop PRC-005. The SDT believes that Protection Systems that trip (or can trip) BES Elements due to a Fault should be included (in the case of a Sudden Pressure Scheme, the control circuitry and DC supply components would apply). The relays mentioned are already covered by the standard, in that they are “Protection Systems that act to trip the generator either directly or via lockout or auxiliary tripping relays.”

Organization	Yes or No	Question 4 Comment
Tennessee Valley Authority		1. Regarding the functional test required every 3 months for "unmonitored communication systems" in Table 1-2 of the PRC-005-2 Draft. TVA feels that a Maximum Maintenance Interval for the Functional Test should be every 12 months until auto-checkback has been fully implemented by the utility. 2. The Implementation Plan for PRC-005-2 Step 4 on Page 2 states: "The Implementation Schedule set forth in this document requires that entities develop their revised Protection System Maintenance Program within twelve (12) months following applicable regulatory approvals, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter twenty-four (24) months following NERC Board of Trustees adoption. This anticipates that it will take approximately twelve (12) months to achieve regulatory approvals following adoption by the NERC Board of Trustees." TVA feels that this is not sufficient time to implement full auto-checkback capability at some utilities. The time schedule of twelve (12) months should be forty-eight (48) months following applicable regulatory approvals. 3. TVA has many excitation transformers directly connected to the generator bus, configured such that a fault on the excitation transformer will cause a generator trip. Is the intent that the revised standard will include these transformers in the applicability? Would they be included by section 4.2.5.1? 4. TVA (Rusty Hardison) has forwarded a slide presentation with six questions to the PRC-005-2 Draft Team requesting consideration as input to the Frequently Asked Questions document accompanying the standard. Thank you for considering.

Response: Thank you for your comments.

1) The SDT believes the four month interval is proper for unmonitored communications systems. The activity related to this interval is to verify basic operating status.

2) The Implementation Plan is intended to facilitate implementation of the standard, not to facilitate modifications to meet the requirements of the standard.

3) The SDT revised Applicability Clause 4.2.5.4 to include excitation transformers connected to the generator bus.

Organization	Yes or No	Question 4 Comment
4) The SDT modified the Supplementary Reference and FAQ document to address these questions.		
Tacoma Public Utilities		1. For components that are part of a time-based PSMP, if correction of Unresolved Maintenance Issues takes place before the maximum maintenance interval expires, is it mandatory to demonstrate (document) these efforts to correct identified Unresolved Maintenance Issues? Is the purpose of Requirement R5 only to avoid compliance jeopardy when an entity discovers a problem during maintenance but cannot correct the problem until after the maximum maintenance interval has expired (as discussed in the Supplemental Reference and FAQ document)? Or, is the purpose also to ensure that all Unresolved Maintenance Issues are documented even if they corrected very quickly and within the maximum maintenance intervals and just considered part of routine maintenance (i.e., Unresolved Maintenance Issues not explicitly documented) in a manner similar to recalibrating a relay? 2. Assume that a component under a time-based PSMP is not considered "monitored" per the PSMP, but in actuality it is. If an alarm comes in, indicating a component problem, would the entity have any additional documentation obligations under PRC-005-2 associated with this alarm, provided that all minimum maintenance activities and maximum maintenance intervals associated with the unmonitored component are satisfied? The concern is that, if there are additional documentation obligations; then many entities may disable monitoring in some cases in order to avoid compliance jeopardy. 3. Assume that an entity treats batteries at certain remote communication sites as if they were applicable to PRC-005-2. These sites are not substations or generating facilities but support the broad communication system, including teleprotection functions. Furthermore, these sites have limited access during some times of the year because of heavy snow or ice. It is conceivable that it may not be possible to meet all minimum maintenance activities or all maximum maintenance intervals (4 and 6 calendar months) unless the site is extensively monitored and/or field personnel expose themselves to hazard. Would any allowances be made in these cases? Would

Organization	Yes or No	Question 4 Comment
		these sites even be applicable to PRC-005-2, since they are not part of a "station" DC supply? 4. It is still unclear whether Section 15.3 permits periodically verifying DC voltage at the actuating device trip terminals as an acceptable method of accomplishing the maintenance activity identified in Table 1-5 for unmonitored control circuitry associated with protective functions. It is recommended that this approach be considered acceptable, provided that auxiliary relays are operated within the maximum maintenance interval. 5. In the Implementation Plan for Requirements R1, R2, and R5, why there is a requirement to "be 100% compliant [with R5] on the first day of the first calendar quarter twelve (12) months following applicable regulatory approvals"? The emphasis of this question is on Requirement R5, which pertains to Unresolved Maintenance Issues. 6. In the Implementation Plan for R3 and R4, to be considered "100% compliant with PRC-005-2," is it only necessary to have completed the applicable minimum maintenance activities one time for the applicable component (which is our assumption)? Or, does being considered 100% compliant under this Implementation Plan imply that two instances of the applicable minimum maintenance activities must have been completed for the applicable component?

Response: Thank you for your comments.

1. The definition of Unresolved Maintenance issue has been revised to specify that it applies to deficiencies that "…cannot be corrected during the maintenance interval..."
2. The SDT believes that as long as all minimum maintenance activities and maximum maintenance intervals associated with a component are completed and documented, no additional documentation obligations are necessary.
3. The SDT does not believe that the scope of the standard refers to communication sites. The SDT believes that a loss of power to the communications systems at a remote site would cause the communications systems associated with protective relays

Organization	Yes or No	Question 4 Comment
to alarm at the substation. At this point, the corrective actions can be initiated. 4. The SDT believes that every trip path from relay to trip coil must be verified. If a trip coil has multiple trip paths, verifying DC voltage at the actuating device would not accomplish the maintenance activity identified in Table 1-5 for unmonitored control circuitry. 5. The SDT believes that the entity be 100% compliant with Requirement R5 on the first day of the first calendar quarter because an Unresolved Maintenance Issue could arise during the first calendar quarter. 6. The Implementation Plan addresses the initial performance of the required activity within the required intervals. The entity should expect to comply with PRC-005-1B until they fully implement PRC-005-2.		
Texas Reliability Entity		1. The Implementation Plan is still overly long and complicated. Registered Entities and Regional Entities will have to track and apply multiple versions of this standard for up to 14 years. It would be preferable to have a much shorter implementation plan, so that only one version of the standard will be applicable at any given time, recognizing that for some Components no action will be required under the standard for a number of years. 2. Referring to R3, R4 and M1 (and other places), it is redundant to add "Protection System" to describe "Components "or "Component Types" based on the "local definitions" provided. Alternatively, the defined term could be changed to "Protection System Component" and used consistently. 3. In Table 1-3, the activity should include verifying that the current and voltage signal values are within tolerances, not just that signal values are present. The minimum activity should include a ratio check and/or burden check of current transformers. Suggest revising to state "Verify that current and/or voltage signal values provided to the protective relays are within the accuracy tolerance of the voltage and current sensing device". 4. In the VSL for R2, we are assuming that the "4% within three years" is a 4% failure rate based on Attachment A, but that is unclear. We suggest clarifying this language

Organization	Yes or No	Question 4 Comment
		to match Attachment A language. 5. What is the basis for the 4% failure rate limit in Attachment A? It would appear that a 4% failure rate is high for protective relays. Does the SDT have a technical justification supporting the selection of 4% as the applicable limit? 6. In Attachment A, item 4 in the "maintain the technical justification" section needs clarification. It can be assumed that the phrase "for the greater of either the last 30 Components maintained or all Components maintained in the previous year" is referring to Components within a specific Segment, but more specific language may be needed. Also, are the references to "prior year" and "previous year" intended to refer to calendar years or 365 days preceding the analysis? 7. In Attachment A, item 5 in the "maintain the technical justification" section needs clarification. We suggest adding a timeframe for the "experience 4% or more Countable Events" phrase. Does this refer to any 12-month period? Additionally, the determination of a timeframe for "4% of the Segment population" is needed. Example- If there are 100 Components in a performance-based Segment in Year 1 and I add an additional 100 Components in Year 2, is the 4% based on 100 or 200?

Response: Thank you for your comments.

1. The SDT disagrees, and believes that having a shorter implementation plan would not allow entities to complete the requirements. The Implementation Plan is designed to allow an entity to systematically implement PRC-005-2 such that an ongoing program may be facilitated.
2. Strictly speaking, you are correct. However, the SDT has elected to include the emphasis, "Protection System" in these locations to help clarify that such components are only in-scope where they are part of the "Protection System."
3. The SDT disagrees. Verify is defined as, "Determining that the component is functioning correctly." If the signals to the relay are beyond tolerance, the component is not functioning correctly.
4. The SDT agrees and has corrected the Requirement R2 VSL to indicate "…no more than…"

Organization	Yes or No	Question 4 Comment
5. The SDT chose 4% because an entity with a small population (30 units) would have to adjust its time intervals between maintenance if more than one countable event was found to have occurred during the last analysis period. A smaller percentage would require that entity to adjust the time interval between maintenance activities if even one unit is found out of tolerance or causes a Misoperation (see Supplemental Reference and FAQ Section 9.1). 6. The SDT affirms that all references to "prior year"and "previous year" refer to "calendar year." 7. The time frame refers to a calendar year. The 4% failure rate is determined from those Component segments tested in the previous calendar year.		
TransAlta Centralia Generation LLC		1.3 Evidence Retention. The standard said: For Requirement R2, R3, R4 and R5, the Transmission Owner, Generator Owner and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance. How to count" the most recent performance ". Is this Standard going forward basis? For some of the protection system component, the maximum maintenance interval is 12 years (such as CT, PT or microprocessor relay) on the standard, how to count the two most recent performance?
Response: Thank you for your comments. For a Compliance Monitor to be assured of compliance, the SDT believes the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding maintenance to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT has specified the data retention in the posted standard to establish this level of documentation, which is consistent with the current practices of several regional entities.		
PacifiCorp		1: The definition of "Protection System" in this version of PRC-005-2 includes "station dc supply associated with protective functions..." as a Protection System component. Page 83 of the FAQ document accompanying the draft standard provides further clarification that the batteries covered under PRC-005-2 are those that "supply the trip current to the trip coils of the interrupting devices that are a part of the Protection System." This statement in the FAQ is much more limiting than the definition of Protection System and may create confusion concerning registered entities' compliance obligations. For example, a registered entity may have one

Organization	Yes or No	Question 4 Comment
		battery / charger system in a station that supplies DC voltage to communication equipment, including that utilized in transfer trip communication, while a separate battery (typically operating at a different DC voltage) is utilized for relay / trip coil operation. In this case, it is unclear whether the battery / charger system utilized for transfer trip communication is subject to the requirements of the standard. PacifiCorp recommends that NERC or the SDT reconcile this apparent inconsistency in the FAQ document. 2: In Tables 1-4(a) thru 1-4(d), the maximum maintenance interval of four calendar months includes inspection “for unintentional grounds.” PacifiCorp seeks clarification on whether this maintenance activity is intended to target the detection of unintentional grounds on the battery bank / rack itself, or a ground located anywhere on the entire DC wiring system. 3: The Violation Severity Level (“VSL”) for R5 - which ranges from a failure to correct 5 or less (“Lower” VSL) to greater than 15 (“Severe” VSL) Unresolved Maintenance Issues - fails to adequately account for the cumulative amount of equipment a registered entity is required to maintain pursuant to PRC-005-2. A better alternative approach may be to base the VSL on the cumulative percentage of Unresolved Maintenance Issues that an entity fails to address and correct. Such an approach would be more consistent with the VSLs for R3 and R4, which are based on a percentage of the total scheduled maintenance. This approach more fairly and reasonably addresses the covered maintenance activities relative to the approach in the VSLs for R5, which are based on a strict count and therefore independent of the cumulative amount of maintenance activities performed by a registered entity. PacifiCorp recommends that the SDT develop an alternative method for determining VSLs for R5 that reflects the scope of an entity’s maintenance activities and the resulting Unresolved Maintenance Issues managed by an entity.

Response: Thank you for your comments.

1. The SDT believes the term “Station dc supply” is clearly defined within the standard, and that the definition should be

Organization	Yes or No	Question 4 Comment
considered when applying the term. Your reference to Page 83 of the Supplemental Reference and FAQ Document clarifies that Table 1-4 of the standard refers to Station Batteries only, and not Communications Site Batteries. 2. The SDT believes the inspection for unintentional grounds applies to the entire DC wiring system. 3. The SDT disagrees and believes the VSL's for Unresolved Maintenance Issues should be a numeric quantity, and not a percentage.		
Essential Power, LLC		1. This DRAFT Standard is written as a prescriptive 'procedure' and not as a 'Standard'. The SDT should revise the Standard to address the goal, or intent, rather prescribing how entities should meet the Standard. 2. Inclusion of non-BES elements within the Standard falls outside of NERC's jurisdiction, as defined in the EPA 2005. The SDT should remove these elements from the Standard. 3. The inclusion of dc circuitry for equipment that is itself not covered under the Standard is not logical and does not contribute to reliability. The SDT should remove this from the Standard.
Response: Thank you for your comments. 1. The SDT believes the standard describes the desired outcomes and is not a 'prescriptive procedure'. The entity is free to determine what maintenance methods are best suited for its program. 2. FPA Section 215(a) Definitions section defines "bulk-power system as … facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof)." That definition then is limited by a later statement which adds the term bulk-power system "does not include facilities used in the local distribution of electric energy." Facilities such as those to which you refer are not solely "used in the local distribution of electric energy," despite their location on local distribution networks. Further, if these facilities were not covered by the reliability standards, reliability gaps would exist.		

Organization	Yes or No	Question 4 Comment
3. The SDT believes that Protection Systems that trip (or can trip) for Faults on the BES should be included. This position is consistent with the SAR for Project 2007-17, and with the position of FERC staff.		
MRO NSRF		1. Article 4.2.1 - The NSRF believes that this article should be revised to say "Protection Systems installed for the purpose of protecting BES Elements only and detecting Faults on BES Elements. Protection Systems designed to protect non-BES elements that incidentally open 100 kV and greater breakers are excluded from the scope of PRC-005-2". This makes it very clear what is included in the scope of the Testing and Maintenance program and what is not. 2. Change the text of "Standard PRC-005-2 - Protection System Maintenance" Table 1-5 on page 21, 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. 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).The NSRF believes that as written the testing of "each" trip coil will result in the increased amount of time that the BES is in a less reliable system configuration. The NSRF hopes that the

Organization	Yes or No	Question 4 Comment
		SDT will consider these changes. 3. The NSRF recommends the statement "Excluding distributed UFLS and distributed UVLS (see Table 3)" be added to the top of Table 1-4(f). 4. Table 3. There will be many DP's that have distributed UFLS (or UVLS) solely on the distribution system (less than 100 kV). The only item these DP's will have to verify under Table 3 "Protection System dc supply" is the Protection System dc supply voltage. Yet, the definition of Protection System, as it relates to dc supply is "Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply)". Our interpretation of Table 3 and Section 15.7 of the Supplementary Reference & FAQ document is that a DP need only check the dc supply voltage at the terminals of the relays. If that is the SDT interpretation as well, we recommend revising Table 3 of the standard to reflect that. Table 3 contains issues that need to be addressed in a similar fashion as discussed for non-UFLS and non-UVLS systems, i.e. Table 1-1. Comparison to independent sources is only one way to check for a reliable AC measuring device. It also appears that monitoring capabilities are not being given any credit in regards to the AC sensing devices, DC supply, or control circuitry themselves. There should be no difference in the way these systems are treated compared to BES Protection Systems. 5. In Section D Compliance, Article 1.3, paragraph 4 the standard requires documentation be kept for the ". . . two most recent performances of each distinct maintenance activity. . .". This needs to clarify that it cannot go back before 06/18/07, as evidenced by the suspension of CAN-0008. Also with some of the testing intervals being 12 years that would dictate a Registered Entity maintain 24 years of records, which is unreasonable. This article should be revised to have documentation for the most current testing interval, if after

Organization	Yes or No	Question 4 Comment
		06/18/07. 6. It is understood that lockout relay testing is important as unexercised lockouts can stick and cause regional outages as experienced at Westwing. However, lockout testing by itself is risky and can lead to local outages. If Registered Entities are required to take on the additional risk of testing lockout relays, dispensation must be granted for outages caused by those tests. The following statement should be included in the standard "No enforcement actions or penalties will result from outages caused by relay testing unless a Registered Entity shows a history of 3 or more test related outages per year for 5 years." 7. In the VSL for Table 4 it seems that the phrase "5% or less" should be "not more than 5%". With the original language it seems like an entity could be found to have an R4 lower VSL violation for "failure" of zero meaning they had done no testing. This VSL is written in the negative and should be rewritten in the positive. 8. The drafting team needs to clarify "maintenance summaries" as stated in Measure M3. This is an ambiguous term that could be interpreted differently amongst entities. If a term such as 'summary' is to be utilized within the standard, a clear definition of what the term is, what it pertains to, where it is located, etc. needs to be included. The NSRF recommends that "maintenance summaries" be defined and included in the "Definition of Terms used in Standard" section. 9. Footnote 1 in the Table sections would be much improved by inserting an example similar to what was provided in Section 8.4 of the Supplemental Reference and FAQ document 10. Additional methods of verification should be allowed for AC measurement monitoring other than simply performing comparison to an independent source. For example, a sudden rate of change in calculated relay MW analog value and/or

Organization	Yes or No	Question 4 Comment
		3Io calculation would give way towards a bad CT and/or path. Loss of potential logic is available in most microprocessor relays today, which is very reliable logic for determining PT/CCVT issues. Consideration should be given to utilities that are capable of performing this type of monitoring in order to allow them to reach that next level of attributes. 11. Please clarify why input/output verification is excluded from the highest level of monitoring related to communications systems (Table 1-2). The way the monitoring attribute is listed does not provide that these will operate when needed. Recommend language be added similar to the monitoring of inputs and outputs described in the relay section (Table 1-1). Table 1-3 should take into account the same concepts mentioned above in regards to AC measurement verification in Table 1-1. There are alternative ways to verify these quantities while still ensuring reliable operation. As such, companies should be given the opportunity to implement them. Additionally, credit should be given to circuit monitoring and alarming in AC circuits with electromechanical relays. If a transducer/alarming relay is placed in the circuit and monitoring is alarmed appropriately, the health of the AC sensing device can be determined. This would essentially provide the same level assurance as mentioned with the microprocessor relays. 12. Clarification is needed on the last row of Table 1-5. Does integrity entail monitoring and alarming of every individual path, if necessary, or is overall integrity sufficient? This statement is once again open to interpretation and leaves the entity at the mercy of the auditor.

Response: Thank you for your comments.

1. The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.

Organization	Yes or No	Question 4 Comment

2. The SDT sees no appreciable change or improvement in the standard with your proposed change, and respectfully declines to modify the draft.
3. The SDT believes that the suggested change would be redundant to the current text of the Table 1-4(f) header.
4. This is an intentional difference between distributed UFLS/UVLS and the remainder of the Protection Systems addressed within the standard because of the distributed nature of distributed UFLS/UVLS and because these devices are usually tripping distribution System Elements. If an entity were to install monitoring equipment for verification of Station DC supply voltage, or other facets of the reduced maintenance activities regarding distributed UFLS/UFLS, Table 1-3 describes the adjusted activities permitted relative to that monitoring.
5. The SDT believes the Implementation Plan is descriptive in that an entity will be 100% compliant with PRC-005-2 when one maintenance period has elapsed. On a continuing basis, in order that a Compliance Monitor can be assured of compliance, the SDT believes that the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding one to validate that entities have been in compliance since the last audit. The SDT has specified the data retention in the posted standard to establish this level of documentation, which is consistent with the current practices of several regional entities.
6. The SDT believes it is left to the entity to determine how to align the requirements of the standard with requirements of other regulations and with operational concerns.
7. The VSL Guidelines, developed in accordance with the FERC VSL Order establish the Lower VSL for stepped VSLs as “5% or less,” the Medium VSL as “more than 5% but less than (or equal to) 10%,” the High VSL as “more than 10% up to (and including) 15%,” and the Severe VSL as “more than 15%.”
8. The SDT believes defining “Maintenance Summaries” is unnecessary. The measure simply lists some types of evidence to demonstrate that an entity has maintained its Protection System in accordance with the standard.
9. The SDT believes that the footnote is adequate, but recognizes that some entities may desire the additional details that are included in Section 8.4 of the Supplementary Reference and FAQ document.
10. The SDT believes that the methods that you suggest would be useful for meeting the 12-calendar-year interval for unmonitored Components. However, for monitored systems with no physical maintenance activities, the SDT is concerned about the quality of some of the methods suggested.

Organization	Yes or No	Question 4 Comment
11. The SDT has modified the last row of Table 1-2 to be similar to the corresponding row of Table 1-1. 12. Section 15.3 of the Supplemental Reference and FAQ provides the following guidance: "Monitoring of integrity means to monitor for continuity and/or presence of voltage on each trip path."		
Duke Energy		1. Duke Energy votes "Negative" because we strongly object to the wording in the Applicability section 4.2.1. We believe that the wording change to PRC-005-2 draft 4 after the Successive Ballot but prior to the Recirculation Ballot expanded the reach of the standard to relaying schemes that detect faults on the BES but are not intended to provide protection for the BES. FERC's September 26, 2011 Order in Docket No. RD11-5 approved NERC's interpretation of PRC-005-1 R1 and R2, stating: "The interpretation clarifies that the Requirements are "applicable 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 [BES] and trips an interrupting device that interrupts current supplied directly from the BES." This interpretation is consistent with the Commission's understanding that a "transmission Protection System" is installed for the purpose of detecting and isolating faults affecting the reliability of the bulk electric system through the use of current interrupting devices." The SDT's response to our comment directed us to Section 2.3 of the Supplementary Reference and FAQ document which states "There should be no ambiguity: if the element is a BES element then the Protection System protecting that element should be included within this Standard." We agree with that statement, but question why the SDT insists on changing Section 4.2.1 to include devices that detect Faults on the BES but which do not provide protection for the BES? Duke Energy's standard protection scheme for dispersed generation at retail stations would become subject to the standard due to the changes in section 4.2.1. These protection schemes are designed to detect faults on the BES, but do not operate

Organization	Yes or No	Question 4 Comment
		BES elements nor do they interrupt network current flow from the BES. In the most recent draft, the relays, current transformers, potential transformers, trip paths, auxiliary relays, batteries, and communication equipment associated with the dispersed generation protection scheme would be subject to the requirements in PRC-005-2. Previous drafts of the standard would not have required Duke Energy to maintain the protection system components associated with dispersed generation schemes at retail stations in accordance to the requirements in PRC-005-2. The new wording in section 4.2.1 would add significant O&M costs and resource constraints due to the inclusion of protection system devices at retail stations without increasing the reliability of the BES. Duke Energy does not believe it was the intent of the standard to include elements that did not have an impact on the reliability of the BES. Duke Energy would prefer the following definition: Protection Systems that are installed for the purpose of protecting BES Elements (lines, buses, transformers, etc.)”. 2. We also note that the Lower VSLs for R3 and R4 include violations for “5% or less,” and R5 for “5 or less” which mandates perfection. We believe that the consequence of a very small number of components having a missed or late maintenance activity is insignificant to BES reliability.” We suggest that a range of 0.5% to 5% would be more reasonable.

Response: Thank you for your comments.

1. The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term “transmission Protection System,” and notes that this term is not used within PRC-005-2; thus, the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses “Protection Systems that are installed for the purpose of detecting Faults on BES Elements.” Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion.
2. NERC criteria for VSLs do not currently permit them to allow some level of non-performance without being in violation. Much

Organization	Yes or No	Question 4 Comment
of this comment appears to be related to the technical content of the standard, not on the VRFs or VSLs.		
PPL Supply NERC Registered Organizations		Although we have provided some suggested changes in these comments, PPL Generation entities voted in favor of this version. We thank the SDT for the effort on this project and believe that the SDT has developed a revision that improves on many aspects of the existing version of PRC-005.
Response: The SDT thanks you for your affirmative vote.		
ExxonMobil Research and Engineering		As written, the current draft of PRC-005-2 discriminates against smaller entities that do not have a population size of 60 for each component type. Historical records provide an accurate account of how specific components have performed in their installed environment. For a set population size, increasing the number of historical data points should improve the accuracy of an entity's calculated mean time between failures, so, if you increase the period over which the historical data must be evaluated, you can compensate for a smaller segment population size. The SDT's current draft prevents smaller entities from using a larger historical data set to make up for a smaller population size when developing a performance based protective system maintenance and testing program. The SDT should reconsider allowing smaller entities to use historical records that extend for period longer than a single year in the development of a performance based program.
Response: Thank you for your comment. Small entities are permitted to aggregate their components with similar components of other entities to meet the component populations, as long as the programs are (and remain) similar – See Section 9 of the Supplementary Reference and FAQ document and the associated footnote to Attachment A. Decreasing the Component population below the requirements of Attachment A will result in an unsound program due to Component populations that are not statistically significant. The Supplementary Reference and FAQ document states, "Any population segment must be comprised of at least 60 individual units; if any asset owner opts for PBM but does not own 60 units to comprise a population then that asset owner may combine data from other asset owners until the needed 60 units is aggregated." Historical data may be good for trending, but may not be suitable for judging current maintenance program effectiveness.		
American Transmission Company, LLC		ATC recommends that the SDT change the text of "Standard PRC-005-2 - Protection System Maintenance" Table 1-5 on page 21, Row 1, Column 3 to:"Verify that a trip coil

Organization	Yes or No	Question 4 Comment
		is able to operate the circuit breaker, interrupting device, or mitigating device." Or alternately, "Electrically operate each interrupting device every 6 years "Basis for the change: 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. ATC 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).ATC continues to recommend a negative ballot since we believe that the testing of "each" trip coil will result in the increased amount of time the BES is in a less intact system configuration. ATC hopes that the SDT will consider these changes.
Response: Thank you for your comment. The SDT sees no appreciable change or improvement in the standard with your proposed change, and respectfully declines to modify the draft.		
Bonneville Power Administration		BPA believes that PRC-005-2 achieves the goal of reducing redundancy and overlap within the PRC standards by consolidating four existing standards into one. BPA's comments are focused on improving the clarity and audit-ability of the proposed standard. 1. Regarding Section D1.3 "Evidence Retention", BPA suggests that the entire first paragraph be removed because for all the instances that follow the first paragraph there is a requirement to keep evidence obtained since the last audit. Therefore, there are no instances where the evidence retention period is shorter

Organization	Yes or No	Question 4 Comment
		than the time since the last audit, and the first paragraph is not necessary. Furthermore, the first paragraph introduces the idea of "other evidence" for which there is no explanation. It is unclear what could be used for evidence other than the items described in the 2. Measures. The idea of "other evidence" should not be introduced without an explanation of what that evidence might be, so this is another reason for removing the first paragraph. 3. Regarding requirements R2 and R4, BPA believes that these two requirements should be combined into a single requirement with two parts. Since both of these requirements deal with performance-based maintenance, it would simplify the standard and improve the flow if they were to be combined. 4. Regarding Table 1-4(f), it is unclear if all of the conditions on the left side need to be met before any of the reduced maintenance activities on the right side are allowed, or if there is a one-on-one relationship between an item on the left and the adjacent item on the right. BPA suggests that the table be reconfigured to clarify the relationship between the conditions on the left and the activities on the right.

Response: Thank you for your comments and support.

1. The SDT has been advised to include this paragraph as the first paragraph in the evidence retention.
2. The list of possible evidence with the measures is not intended to provide a comprehensive list of all type of evidence that may be useful. The entity is provided the flexibility to use other evidence that they deem relevant.
3. Requirements R2 and R4 are separate, as they address two specific requirements; one to establish a performance-based PSMP according to criteria, and the other to implement that PSMP.
4. There is a one-to-one correspondence between the right and left columns, and the SDT believes that further clarification is unnecessary.

Organization	Yes or No	Question 4 Comment
CenterPoint Energy		1. CenterPoint Energy recommends retaining an option to utilize technology for monitoring trip coil continuity as an alternative to the maintenance activity in Table 1-5. The Table 1-5 requirement to "Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating devices (regardless of any monitoring of the control circuitry)" appears to address breaker maintenance, instead of Protection System Controls. In the Supplementary Reference and FAQ, monitoring is described as greatly reducing the time between a component failure and discovery of that failure. 2. For the “Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices (Excludes non-BES trip coils)”, the Table 3 requirement is to “Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic)” every 12 calendar years. CenterPoint Energy recommends this requirement be revised to “No periodic maintenance specified”. CenterPoint Energy believes this to be a commissioning task, not a preventive maintenance task. A preventive maintenance task, such as the above, is unnecessary for distributed UFLS and UVLS system components. The overriding performance, or “risk-based”, NERC Reliability Standards for UFLS are PRC-006 and PRC-007 where an entity is required to shed their obligated firm load amount. 3. For the “Unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays”, the Table 1-5 requirement is to “Verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices” every 12 calendar years. CenterPoint Energy recommends this requirement be revised to “No periodic maintenance specified”. CenterPoint Energy believes that verifying all tripping paths is a commissioning task, not a preventive maintenance task. Alternatively,

Organization	Yes or No	Question 4 Comment
		CenterPoint Energy recommends specifically excluding panel wiring and requiring only cabling between panels and interrupting devices be verified. Requiring trip path verification to include panel wiring complicates maintenance while focusing on a component that is not subject to age-related degradation in addition to, historically, not being a source of protection system failures. This type of testing can negatively impact BES system reliability with the outages that are required and by exposing the electric system to incorrect tripping.
Response: Thank you for your comments. 1. While trip coil monitors may demonstrate continuity, they do not fully demonstrate operability. 2. The SDT disagrees regarding UFLS and UFLS-related control circuitry maintenance, and believes that the maintenance specified is appropriate. 3. The SDT disagrees with your proposal regarding Table 1-5 for dc control circuits and auxiliary relays which may be a critical part of a tripping scheme.		
Central Lincoln		Central Lincoln appreciates the good work the SDT has done. We believe this particular team has actually listened to our comments and made changes where needed. Thanks.
Response: The SDT thanks you for your affirmative vote.		
Constellation/Exelon		Constellation/Exelon thanks the drafting team for the hard work on the PRC-005 standard. The standard language made significant progress; however, below are outstanding issues of concern: Table 1-3 1. Table 1-3 should not include current transformers (CTs). The tests mandated by this draft seeks to measure that a signal is “provided to the protective relay” however, for CT’s this test merely confirms that a signal is sent, not that it reached the correct protective relay.

Organization	Yes or No	Question 4 Comment
		2. The maintenance activity in Table 1-3 for PTs and CTs as they relate to electro mechanical relays should be left to the discretion of the Generator Owner. In order to meet the required activity specified in PRC-005-2 draft 2 Table 1-3, the generating unit would be required to take readings with meters while the unit is operating. This practice introduces a risk of tripping the unit inadvertently. The risk of tripping the unit while performing this maintenance activity is contrary to the intended purpose of PRC-005 and introduces a potentially adverse affect on the reliability of the BES. Such testing is not recommended by suppliers. Battery Testing 3. The Tables describing battery testing could be consolidated into less granular breakdown and thus alleviate some of the associated compliance burden and avoid potential confusion. 4. Further to battery testing, given the quantity of batteries and the shorter interval cycles, the four calendar month requirement for batteries is too rigid as a firm four months. Similar to how a definition of annual can have a boundary such as within 9 to 16 months; battery testing intervals should allow a boundary such as "three times per year and not more than 6 months between each and average intervals not exceeding four months." 5. Please confirm that references throughout Standard to battery/batteries relate to the entire battery bank and not to the individual battery cells unless specifically mentioned. Similarly, battery charger maintenance activity should relate to the battery charger in its entirety and not to individual parts or components. Auto Synchronizing Systems and Relays 6. The drafting team should clarify in the language that testing of auto synchronizing

Organization	Yes or No	Question 4 Comment
		systems and relays is excluded. Applicability 7. To make 4.2.5.4 under Facilities more clear, please remove the term "generator-connected". 8. When the SDT changed the original PRC-005 applicability language from "...affecting the reliability of the BES..." to the new 4.2.1 language "...that are installed for the purpose of detecting faults on BES elements (lines, buses, transformers, etc.)", they opted to exclude the second half of this sentence taken from the PRC-005-1a Interpretation, which read "...and trips an interrupting device that interrupts current supplied directly from the BES." By doing so, the SDT failed to recognize that some Protection Systems can be responsive to faults on the BES, but still have no effect on the reliability of the BES. The change in 4.2.1 may unintentionally expand the scope of PRC-005.Depending on how Section 4.2.1 is interpreted, it could create a perverse incentive to disable, or not apply, reverse directional protection on the secondary (at voltages less than 100kV) of radially connected load-serving transformers. Such relaying typically uses available units in a multifunction device, and while not critically necessary for fault clearing, it is applied because it adds a benefit at no incremental cost with minimal security risk, and it will not interrupt a BES element if it operates insecurely. It also improves reliability to connected distribution load, in the event a BES transmission line faults during abnormal switching, by coordinating with non-directional overcurrent relays that would otherwise interrupt the entire load. Furthermore such directional relaying would only operate after the faulted BES line is already removed from any connection at BES voltages via its high voltage (>100kV) circuit breakers. Viewed in an expansive way, the proposed 4.2.1

Organization	Yes or No	Question 4 Comment
		language could bring into scope these relays as well as tripping circuits of distribution voltage circuit breakers that are normally operated in a radial configuration. It would be reasonable for a TO to disable this relaying, rather than accept these consequences. In the previous comment period (Sept 2011), industry raised similar concerns and to most of the commenters, the SDT responded with the following statement:"The SDT believes that the Applicability as stated in PRC-005-2 is correct and that it supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, "transmission Protection System", and notes that this term is not used within PRC-005-2; thus the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting faults on BES Elements." Please see Section 2.3 of the Supplementary Reference and FAQ document for additional discussion." Unfortunately, this response fails to address the concerns raised above. Entergy previously suggested the following language for 4.2.1:"Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.) and trips an interrupting device that interrupts current supplied directly from the BES Elements."This language is appropriate and addresses industry concerns. We ask that the SDT adopt this language as Section 4.2.1. Evidence Retention 9. It is not necessary and is undesirable to reiterate the language from the NERC Rules of Procedure (Appendix 4C 3.1.4.2) in the standard. Stating such language in two places is redundant and future changes to this section of the Rules of Procedure language will create compliance conflict. While this language may be recommended for inclusion as new boilerplate-type language for NERC standards

Organization	Yes or No	Question 4 Comment
		and may be used in other recently revised standards, the potential conflict should be taken into account and avoided for PRC-005. The first paragraph in section 1.3 should be removed. 10. Further, the standard language should dictate data retention relevant to the standard activities and not merely default to the time period in between audits. The Rules of Procedure language enables CEAs to confirm compliance for the full audit period, but the Standard retention language allow for a more reasoned obligation for evidence retention. Specific to this standard, two or three years of evidence for certain components, such as battery tests, is sufficient to demonstrate an entity's PSMP program. On a positive note, standardizing the requested evidence information is helpful.

Response: Thank you for your comments.

1. Regarding current transformers, the SDT disagrees, and notes that the table specifies that the entity verify that the signal is provided to the relay.
2. Regarding testing for currents or potentials behind a Generator Operator's electromechanical relay panel, the SDT believes that it is possible during a 12-year interval to find a reasonably low-risk opportunity to perform the required test. Please refer to Section 15.2.1 of the Supplementary Reference and FAQ document for a discussion of this topic.
3. The existing battery tables have evolved such that entities may easily locate the specific table that applies to the technology being used in order to improve clarity and avoid confusion.
4. Regarding battery testing, the SDT believes that sufficient industry expertise supports a four-month interval requirement.
5. The SDT confirms that most of the battery requirements apply to the entire battery bank, and not necessarily to each battery jar or cell; the same is true for battery chargers. Those requirements specific to individual cells are clearly indicated.
6. Automatic synchronizing relays (which generally close circuit breakers, rather than trip them) are not covered by the Applicability.
7. 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 stated in Applicability 4.2.5.1.
8. The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. The SDT observes

Organization	Yes or No	Question 4 Comment
that the approved Interpretation addresses the term, "transmission Protection System," and notes that this term is not used within PRC-005-2; thus, the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses "Protection Systems that are installed for the purpose of detecting Faults on BES Elements." Please see Section 2.3 of the Supplementary Reference Document for additional discussion. 9. The SDT has been advised to include this paragraph as the first paragraph in the Evidence Retention section. 10. For the Compliance Monitoring Authority to be confident that the corrective action is being implemented, the entity should expect to demonstrate progress toward correcting the Unresolved Maintenance Issue, such as the evidence suggested in Measure M5 (with additional suggested evidence added). The SDT has specified the data retention in the posted standard to establish this level of documentation, which is consistent with the current practices of several regional entities.		
DTE Energy		1. DECo does not agree with the 6 year interval for the majority of the Protection System components. There are not sufficient problems found on routine maintenance based on a 10 year interval that would justify that significant of a reduction in the maintenance interval. 2. Also, with respect the station batteries specifically, station batteries, DECo recommends the elimination of the 4 month inspection as annual inspections have been sufficient for early diagnosis of potential issues. Advanced monitoring is not practical at this time as it does not appear that the technology required to forgo the 4 month inspection is readily available.
Response: Thank you for your comments. 1. The SDT believes the intervals and activities specified are technically effective, in a fashion that may be consistently monitored for compliance. It is left to the entity to determine how to align these requirements with requirements of other regulations and with operational concerns. If the relevant components are monitored, more lengthy intervals may be utilized. Performance-based maintenance is an option to increase the intervals, if the performance of these devices supports those intervals. 2. Regarding battery testing, the SDT believes that sufficient industry expertise supports a four-month interval requirement.		
FirstEnergy		FE asks that the team clarify the intent of certain aspects of the applicability section:

Organization	Yes or No	Question 4 Comment
		1. Sec. 4.2.5.4 - For transformers supplying unit auxiliaries, protective functions that provide for transferring of auxiliaries without tripping the generating unit should not be included. Also, we believe that the term "station service transformer" is being used inaccurately. As currently written, the section includes all the protection systems for station service transformers for generators that are a part of the BES. It states, "Protection Systems for generator-connected station service transformers for generators that are part of the BES." Generating facilities may have transfer schemes on the auxiliary transformer to transfer equipment to a reserve transformer instead of tripping the unit. These protection systems should not be included in the Facilities for PRC-005-2, since the BES is not affected. But since a station service transformer, by definition (IEEE Std. 505), is "a transformer that supplies power from a station high voltage bus to the station auxiliaries and also to the unit auxiliaries during unit startup or shutdown or when the unit auxiliaries transformer is not available, or both." [Ed. note: a.k.a. Start-Up Transformer or Cranker], the terminology "generator-connected station service transformer" is confusing and easily subject to misinterpretation. 2. Also, there needs to be consistency of use of terms between the standard and its Supplementary Reference document. On pages 32 and 33 of the FAQ, the following questions and their respective answers should be consistent with use of terms and replace "station service" with "auxiliary" as follows: FAQ Question - Please provide a sample list of devices or systems that must be verified in a generator, generator step-up transformer, and generator connected auxiliary transformer to meet the requirements of this Maintenance Standard.FAQ Question - In the case where a plant does not have a generator connected auxiliary transformer such that it is normally fed from a system connected

Organization	Yes or No	Question 4 Comment
		auxiliary 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) auxiliary transformer will result in a trip of a BES generating facility? Therefore, for consistency between the reference FAQ document and the standard, we suggest that "station service" be replaced with "auxiliary" in 4.2.5.4 and read as follows: "Protection Systems for generator-connected auxiliary transformers used on generators which are part of the BES, that act to trip the generator either directly or via lockout or tripping auxiliary relays."
Response: Thank you for your comments. 1. Applicability Section 4.2.5.4 specifically addresses the Protection Systems that act to trip the generator, and the "station service transformer" term seems to be the most consistently-used term for this application. 2. The SDT modified the Supplementary Reference and FAQ document for consistency with the standard.		
Kansas City Power & Light		1. For clarity, change the text of "Standard PRC-005-2 - Protection System Maintenance" Table 1-5 on page 21, 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". 2. Countable Event as proposed is somewhat unclear. Recommend the following language: Countable Event - A Component which has failed and requires repair or replacement, any condition discovered during the maintenance activities in Tables 1-1 through 1-5 and Table 3 which requires corrective action, or a Misoperation attributed to hardware failure or calibration failure. Misoperations due to any other reason are not included in Countable Events.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. 1. The SDT believes it is important that each individual trip coil be verified. 2. The SDT does not believe that the changes you suggest improve the standard.		
BAE Batteries USA		Major comments have been addressed in Question 3.
Manitoba Hydro		Manitoba Hydro is voting negative for the following reasons: 1 - Battery inspection and verification interval - Manitoba Hydro maintains that the battery inspection interval should be extended to 6 months. The 4 month interval is too frequent based on our experience and while IEEE std 450 (which seems to be the basis for table 1-4) does recommend intervals, it also states that users should evaluate these recommendations against their own operating experience. Manitoba Hydro has more than ten years of experience using its existing battery inspection intervals and Manitoba Hydro's reliability data has proven that the 6 month inspection interval is suitable for Manitoba Hydro. Manitoba Hydro's battery maintenance tasks were derived from a reliability study of Manitoba Hydro stationary batteries, and the tasks and intervals are suitable given Manitoba Hydro's installed plant, design criteria, climate, and reliability performance. A more frequent inspection interval might be more suitable to specific utilities with material differences in climate, design, installed apparatus, and performance, but it is not suitable for Manitoba Hydro and may be more than is required for many other utilities. To use a more frequent inspection interval would penalize Manitoba Hydro which has been diligently performing battery inspections for many years, with no resulting increase in reliability. It would also potentially adversely affect reliability by diverting resources away from projects that are critical to reliability to meet this maintenance interval. In addition, the 4 month time period proposed for basic battery verification and inspection interval is not aligned with the more detailed 18 month battery verification and inspection interval which will result in additional and unnecessary site visits and maintenance activities. As well, Manitoba Hydro does not feel that the SDT has provided sufficient technical basis to support a 4 month battery inspection and verification interval and requests

Organization	Yes or No	Question 4 Comment
		that further justification and external reference be provided. 2 - PBM not permitted for batteries - Manitoba Hydro disagrees with the SDT's basis for not permitting the use of PBM for batteries. The reasons provided by the SDT for disallowing them are that batteries are perishable and involve chemical reactions. However, it is our understanding that many other industries rely on performance based maintenance programs when dealing with similar equipment. We would appreciate an external reference or source which supports the claim that equipment with these characteristics cannot have a performance based maintenance system applied to them. 3 - Phased Implementation Plan - Manitoba Hydro maintains its position that prescribing how an entity must reach full compliance with PRC-005-2 will provide a negligible improvement in reliability while significantly increasing the compliance burden. PRC-005-2 affects a large number of assets and proving compliance for the prescribed percentages of assets during the transition period creates unnecessary overhead with no added value. We suggest that the requirement to demonstrate the percentage of assets currently under PRC-005-1 vs. PRC-005-2 be removed, that entities should be given a single compliance date for each of the maintenance intervals and be allowed the flexibility to schedule and complete their maintenance as required while transitioning to the defined time intervals in PRC-005-2, and that NERC measures progress on reaching PRC-005-2 intervals using means other than Compliance measures such as industry surveys. 4 - Data Retention Requirements - The data retention requirements are too uncertain for two reasons. First, the requirement to "provide other evidence" if the evidence retention period specified is shorter than the time since the last audit introduces uncertainty because a responsible entity has no means of knowing if or when an audit may occur of the relevant standard. Secondly, it is unclear what 'other evidence', besides the specified evidence in the Measures, an entity may be asked to provide to demonstrate it was compliant for the full time period since their last audit.

Organization	Yes or No	Question 4 Comment
Response: The SDT thanks you for your comments. 1. The SDT believes that sufficient industry expertise supports a four-month interval. 2. The SDT believes that batteries cannot be a unique population segment of a Performance-based Maintenance (PBM) Program because there are too many variables in the electrochemical process to completely isolate all of the performance-changing criteria necessary for using PBM on battery systems. 3. The SDT disagrees with your proposal for a phased implementation plan. 4. The SDT has been advised to include this paragraph as the first paragraph in the evidence retention section.		
Alber Corporation		My comment is in regard to the proposed maintenance tasks associated with ohmic testing and capacity testing of lead-acid batteries affected by PRC-005-2.The option is given to the battery use to perform either inter cell/unit ohmic tests OR battery capacity tests whichever suits the user. The two tests, while related, are not directly interchangeable with one another. Ohmic tests are intended to be used as a tool during battery maintenance inspections to determine the general state of health (condition) of the battery as a whole. Capacity tests are intended to demonstrate the actual capacity of a battery. Ohmic tests cannot be substituted for capacity tests. Alber has pioneered the development of portable and fixed internal resistance test equipment for stationary lead-acid batteries since 1972. Through years of research, testing in real-world applications and development, Alber has conclusively determined that there is a direct relationship between internal cell resistance and capacity. However, because this correlation is not linear, ohmic measurements should not be used to calculate capacity or remaining life. Ohmic measurements should be used as a supplement to capacity testing and not as a replacement. These measurements are very valuable in identifying developing problems between the capacity testing intervals and for determining whether a battery string is going to perform its intended mission. IEEE 1188-2005 for VRLA batteries agrees with this and recommends measurement of this parameter once every three months. While not specifically recommended in IEEE 450-2010 for vented lead-acid batteries, ohmic measurements can provide early warning of potential failure and should be performed at least

Organization	Yes or No	Question 4 Comment
		annually. Again, if readings result in doubt that a battery will perform as intended, follow up capacity testing is recommended. A battery discharge test completely simulates the operating environment and therefore conclusively proves that a battery can perform during an emergency. The results of these tests will help set the priority for capacity testing as the user becomes more familiar with their batteries and may assist in extending capacity test intervals. The intention of the proposed NECR PRC-005-2 standard as it relates to the DC supply, and, in particular, the station battery is to increase reliability of the bulk electric system (BES) in north America. In its current draft form, PRC-005-2 proposes the utility may perform internal ohmic measurements or perform capacity, but both tests are not required. It would appear therefore; that the Standards Drafting Team (SDT) has made the assumption that test results obtained from measuring cell internal ohmic values is the same as performing a capacity test. It is not, and to provide the option to perform one test or the other runs counter to industry recommended practices. Such maintenance practices will, in effect, ultimately reduce the reliability of the BES rather than improve it. Periodic capacity testing on a 5 year interval for VLA batteries, and a 2 year interval for VRLA batteries is consistent with IEEE 450-2010 and IEEE 1188-2005 recommended practices respectively. It should be part of a complete maintenance program designed to maximize the DC supply's availability when needed. Respectfully submitted, Richard Tressler Alber Corp.
Response: Thank you for your comment. The SDT agrees with your statement, and those of others, concerning the true capacity of the station battery and relating it to internal ohmic measurements. Tables 1-4a, 1-4b and 1-4c have been modified for clarity, and the Supplemental Reference and FAQ Document has been modified to further elaborate on these concerns.		
NIPSCO		Per NIPSCO Tech Service Dept : There is a need for NERC to provide a format for maintenance reports. Also, it would help if specific test requirements for relays were provided.
Response: Thank you for your comments. The SDT do not believe it is necessary or appropriate to prescribe a specific format for test results or test requirements.		
PNM Resources		PNM Resources appreciate the outstanding work of the SDT! We offer two comments

Organization	Yes or No	Question 4 Comment
		for consideration by the SDT. 1) We believe that the 6 Calendar Month battery cell/unit internal ohmic value measurement for VRLA Batteries may be more frequent than we believe is necessary to maintain reliability. PNM has witnessed no significant failure patterns with VRLA batteries in our system and we currently do impedance testing of all Transmission Station Batteries on a 2-year basis. 2) We also believe that system constraints could arise that will make it difficult to “verify all paths of the trip circuits inclusive of all auxiliary relays through the trip coil(s) of the circuit breakers or other interrupting devices” as specified in Table 1-5 for “unmonitored control circuitry associated with protective functions inclusive of all auxiliary relays”. Thank you for your consideration.
Response: Thank you for your comments. 1. The SDT believes that it is necessary to verify that the station battery can perform as manufactured by evaluating the cell/unit parameters to station battery baseline if a performance or modified performance test is not conducted. Please see Section 15.4 of the Supplementary Reference and FAQ Document for a discussion of this topic. 2. The SDT believes the intervals and activities specified are technically effective, in a fashion that may be consistently monitored for compliance. It is left to the entity to determine how to align these requirements with requirements of other regulations and with operational concerns.		
American Electric Power		PRC-005-2 is intended to supersede the existing standard PRC-017-0 "Special Protection System Maintenance and Testing". As it is currently written, an Entity with a Special Protection System will be required by R1 to select either a time-based, performance-based or combination maintenance method for the Entity's SPS. Since Special Protection Systems are not frequently installed, it is unlikely that an Entity will be able to meet the requirement of R2 and Attachment A that the Segment population contain 60 components for all components of the SPS. This will require the Entity to utilize the time-based maintenance method for at least some

Organization	Yes or No	Question 4 Comment
		components in the SPS. Under the time-based maintenance method and R3, the Entity will be required to utilize the minimum maintenance activities and maximum maintenance intervals prescribed within Tables 1-1 through 1-5, Table 2, and Table 3. Special Protection Systems by their nature may physically include components that are not listed in the NERC definition of Protection System and therefore are not included in the tables of PRC-005-2. The standard, as currently drafted, does not clearly provide a means for an Entity with a Special Protection System to establish minimum maintenance activities and maximum maintenance intervals for components that have been declared by their Region as part of a Special Protection System but that are not included in the NERC definition of Protection System.
Response: The SDT thanks you for your comments. The SDT does not perceive the gap in maintenance requirements that you describe for SPSs.		
US Bureau of Reclamation		1. Re Terms defined for use only within PRC-005-2: The standard provides definitions which will not be incorporated into the Glossary of Terms. This would allow the definitions as used in this standard to conflict with the definition used in other standards if this practice becomes more widespread and would reduce the cohesiveness of the standard set. 2. Re The definition of Components: The standard defined what constitutes a control circuit as a component type with "Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices." The standard then modified the definition by allowing "a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry." The definition should not be dependent upon practice. This makes the definition a fill in the blank definition. Either eliminate the allowance or remove the definition of control circuit.
Response: The SDT thanks you for your comments.		

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 4 Comment</th></tr>
<tr><td colspan="3">1. The standard specifies that the terms used are intended for this standard only; therefore, there should no conflict with their use in any other PRC standard.
2. The intent of the different means of identifying control circuitry was to accommodate various entities’ philosophies on testing these circuits. Regardless of how an entity chooses to identify their control circuitry, the entity must meet the requirements of the standard regarding maintenance of control circuitry.</td></tr>
<tr><td>ReliabilityFirst</td><td></td><td>1. ReliabilityFirst votes in the negative for this standard primarily due to the language in Requirement R5. The language in Requirement R5 is subjective and non-measurable in its present state. ReliabilityFirst offers the following comments for consideration.
2. Definition of “Component”
a. The language stating “discrete piece of equipment” within the first sentence is unclear and open ended. ReliabilityFirst suggests the following modified language for the first sentence in the definition of “Component”: “A Component is a piece of equipment that is one of the five specific element included in a Protection System, including but not limited to a protective relay or current sensing device.”
3. Definition of “Unresolved Maintenance Issue”
a. There may be instances when a deficiency is identified and corrected during the maintenance itself. For further clarity and to address this circumstance, ReliabilityFirst recommends the following modification for consideration: “A deficiency identified during a maintenance activity that could not be corrected and causes the component to not meet the intended performance and requires follow-up corrective action.”

4. Facilities Section 4.2.1
a. This is too limited or selective in only including Protection Systems that are installed on BES Elements to strictly detect Faults. There are a number of relays</td></tr>
</table>

Organization	Yes or No	Question 4 Comment
		that are installed to detect non-Fault but abnormal conditions such as power swings/out of step and overvoltage that should not be excluded from a maintenance program. ReliabilityFirst recommends the following language for consideration: "Protection Systems that are installed for the purpose of protecting BES Elements (lines, buses, transformers, etc.)" 5. Facilitates Section 4.2.2 a. It is unclear what requirements the phrase "installed per ERO underfrequency load-shedding requirements." is referring to. Is it NERC UFLS Requirements, Regional UFLS Requirements, etc.? To be consistent with section 4.2.3, ReliabilityFirst recommends the following for consideration: "Protection Systems used for underfrequency load-shedding systems installed to arrest declining frequency, for BES reliability. 6. Requirement R3 a. For time-based maintenance program(s), there is no safeguard if more than 4% Countable Events are experienced during a maintenance interval. ReliabilityFirst recommends adding an new Subpart 3.1 (similar to the language for performance-based in Attachment A): "3.1 If the Components in a Protection System Segment maintained through a time-based PSMP experience 4% or more Countable Events, develop, document, and implement a Corrective Action Plan to reduce the Countable Events to less than 4% of the Segment population within 3 years." 7. Requirement R5 a. Requirement R5 has language which states "...shall demonstrate efforts to correct...". ReliabilityFirst believes this language is subjective and non-measurable. It will be difficult in determining what amount of demonstration an entity will need to provide in order to be compliant. There is also no timeframe in which the correction needs to be completed (is it 30 days or 30 years?). ReliabilityFirst believes measurable language such as "shall correct" or "shall

Organization	Yes or No	Question 4 Comment
		have and implement a Corrective Action Plan" should be incorporated within the requirement. 8. Table 1-2 a. For "Any communications system with continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function" ReliabilityFirst believes the maintenance interval is too short. Carrier communication failures are a major cause of Misoperations. Many have automatic checkback and are monitored but continue to fail during Fault conditions. ReliabilityFirst recommends a maintenance interval of 6 years. b. For "Any communications system with continuous monitoring or periodic automated testing for the performance of the channel using criteria pertinent to the communications technology applied" ReliabilityFirst believes a maintenance interval should be required. ReliabilityFirst recommends a maintenance interval of 12 years. 9. Table 1-3 a. For "Any voltage and current sensing devices not having monitoring attributes of the category below." ReliabilityFirst recommends a maintenance interval of 6 years. b. For "Voltage and Current Sensing devices connected to microprocessor relays with AC measurements are continuously verified by comparison of sensing input value..." ReliabilityFirst believes the concept of never having to do any testing just because you have continuous monitoring is fundamentally flawed in this table as well as 1-5 and 2. Continuous monitoring and measurement comparison cannot test everything, such as loss of ground, multiple grounds and turn-to-turn failures, and monitoring itself can fail. ReliabilityFirst recommends a maintenance interval of 12 years. 10. Table 1-5 a. ReliabilityFirst recommends adding "auxiliary tripping devices" to

Organization	Yes or No	Question 4 Comment
		Electromechanical lockout devices in row 2 of Table 1-5. If lockout relays are maintained every six years auxiliary tripping devices should be as well. ReliabilityFirst recommends the following language for considerations: "Electromechanical lockout devices and auxiliary tripping devices which are directly in a trip path from the protective relay to the interrupting device trip coil (regardless of any monitoring of the control circuitry)."

Response: The SDT thanks you for your comments.

1. Requirement R5 is expressly focused on allowing entities to resolve deficiencies in an effective manner, rather than performing "band-aid" fixes. Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the recognition that more complex unresolved maintenance issues could require more time to resolve effectively than there is time remaining in the maintenance interval, yet the problems must eventually be resolved. The SDT believes that corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "Unresolved Maintenance Issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval."
2. The SDT believes it important to distinguish between component "types" (of which there are 5) and individual components (of which there are numerous examples), and believes that you are confusing the two concepts.
3. The definition of "Unresolved Maintenance Issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval."
4. The SDT believes your proposed language for Applicability Section 4.2.1 is overly broad and could lead to unintentional application of PRC-005-2 to other as-of-yet unidentified systems.
5. The SDT intends that this refers to either NERC UFLS requirements or regional UFLS requirements.
6. Countable Events apply only to entities that utilize a performance-based PSMP (Requirements R2 and R4). For entities that use a time-based program, the establishment of maximum intervals within the standard relieves the entity from having to have any

Organization	Yes or No	Question 4 Comment
basis, etc., that the intervals used are appropriate, as long as those intervals conform to the tables. 7. Management of completion of the identified Unresolved Maintenance Issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requires battery replacement as part of the long-term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible Unresolved Maintenance Issues, or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "Unresolved Maintenance Issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval." 8. a) The SDT believes that sufficient emphasis is placed on communication system checks and maintenance. The SDT also believes that more frequent hands-on testing will be no more effective in finding problems than the automated monitoring of these functions. b). The SDT believes that continuous monitoring requirements, as already drafted, will drastically reduce risk to the BES. 9. a) The intervals and activities specified are believed by the SDT to be technically effective, in a fashion that may be consistently monitored for compliance. Entities are empowered to develop PSMPs that exceed these requirements, if they determine such a PSMP to be necessary. b). The SDT believes that continuous monitoring is equivalent to actually conducting the maintenance activities otherwise specified at a far more frequent interval than would be possible with physical hands-on maintenance; and, therefore, improves reliability. The SDT has also identified throughout the tables specific activities that they believe to not be effectively conducted via monitoring. 10. The SDT believes the intervals and activities specified for auxiliary relays are technically effective, and believes sufficient emphasis is placed on auxiliary tripping relay maintenance.		
ATCO Electric Ltd		1. Table 1-4(a) Vented Lead-Acid (VLA) Batteries: ATCO Electric has a number of

Organization	Yes or No	Question 4 Comment
		remote substations that are difficult to access frequently. The requirement for a 4 calendar month inspection for electrolyte level is too frequent. (i) Does alarm/monitor technology exist for electrolyte level in battery design today? For in-service battery systems, if battery alarm/monitor technology exists, a capital project is required to retrofit each battery system and this kind of retrofit work could be detrimental to both the battery design life as well as the battery reliability. (ii) The electrolyte level requirement would become achievable if electrolyte level inspection was moved to the 18 calendar months category, or if the 4 calendar months frequency was increased to 8 calendar months. 2. Table 1-4(b) Valve Regulated Lead Acid (VRLA) Batteries: ATCO Electric has a number of remote substations that are difficult to access frequently. 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. 3. Table 1-5 Control Circuitry When a breaker is opened, there is no indication on which trip coil is actually operated. How do market participants demonstrate compliance for "verify that each trip coil is able to operate..."? The verification of trip coil health is done during breaker maintenance with various maintenance durations that maybe longer than 6 years depending on breaker types. 4. The requirement of "verify electrical operation of electromechanical lockout

Organization	Yes or No	Question 4 Comment
		devices" introduces high risk of human error outages to the BES system and diminishes the reliability gain from performing this activity. The drafting team should consider lockout relay failure rates, onerous tasks of blocking each trip contacts in many BES elements' tripping circuits, imposed risk, required resources in the overall reliability benefit gained by performing the lockout relay maintenance.
Response: The SDT thanks you for your comments. 1. Devices to monitor electrolyte levels are available. The SDT believes that the four-month interval for checking electrolyte level (absent monitoring) is appropriate, as low electrolyte level may impair the ability of the battery to function properly. 2. The SDT believes that the six-month interval for evaluation of cell/unit ohmic parameters to baseline is appropriate, as degradation of these parameters may impair the ability of the battery to function properly. 3. Breaker control circuitry is typically designed with facilities, such that individual trip coils can be isolated for observation. Also, it may be possible to distinguish operation of individual trip coils by determining what devices initiate those trip coils. 4. The SDT believes that electromechanical lockout relays need periodic operation. As such, these devices are required to be exercised at the same six- year interval required for electromechanical relays. The SDT recognizes the risk of human error trips when working with testing of lockout devices, but believes these risks can be managed. Performance-based maintenance is an option if you want to extend your intervals beyond six years.		
Florida Municipal Power Agency		The applicability of the standard should be modified to reflect the FERC approved interpretation PRC-005-1b Appendix 1 that basically says that applicable Protection Systems are those that protect a BES Element AND trip a BES Element. The interpretation states: The applicability as currently stated will sweep in distribution protection: “4.2.1 Protection Systems that are installed for the purpose of detecting Faults on BES Elements (lines, buses, transformers, etc.)”Many (most) network distribution systems that have more than one source into a distribution network will have reverse power relays to detect faults on the BES and trip the step-down transformer to prevent feedback from the distribution to the fault on the BES. This is not a BES reliability issue, but more of a safety issue and distribution voltage issue.

Organization	Yes or No	Question 4 Comment
		These relays would be subject to the standard as the applicability is currently written, but, should not be and they are currently not within the scope of PRC-005-1b Appendix 1 because the step-down transformer (non-BES) is tripped and not a BES Element (hence, the "and" condition of the interpretation is not met). There are many other related examples of distribution that might be networked or have distributed generation on a distribution circuit where such reverse power relays, or overcurrent relays with low pick-ups, are used for safety and distribution voltage control reasons and are not there for BES Reliability. To make matters worse, for these Reverse Power relays, it is pretty much impossible to meet PRC-023 because the intent of the relay is to make current flow unidirectional (e.g., only towards the distribution system) without regard for the rating of the elements feeding the distribution network. So, if these relays are swept in, and if they are on elements > 200 kV, then the entity would not be able to meet PRC-023 as that standard is currently written. So, the SDT should adopt the FERC approved interpretation.
Response: Thank you for your comments. The SDT believes that the Applicability, as stated in PRC-005-2, is correct and supports the reliability of the BES. The SDT observes that the approved Interpretation addresses the term, “transmission Protection System,” and notes that this term is not used within PRC-005-2; thus, the interpretation does not apply to PRC-005-2. PRC-005-2 specifically addresses “Protection Systems that are installed for the purpose of detecting Faults on BES Elements.” Please see Section 2.3 of the Supplementary Reference and FAQ Document for additional discussion. Reverse power relays and low-set overcurrent relays, as discussed in your comment, are not installed for detecting Faults on BES elements. The SDT does not understand your concerns regarding PRC-023, but we suggest you provide those concerns to the team working on that standard.		
Ingleside Cogeneration LP		The derivation of the implementation plan apparently incorporates the “requirements” of NERC’s Compliance organization, which has released several CANs on the topic. This is exactly backwards, and has led to at least one CAN which has been withdrawn due to legal overreach. However, the plan as written is very complex. We believe that diagrams of acceptable time frames should be included in the implementation plan so that industry stakeholders can better assess the impact

Organization	Yes or No	Question 4 Comment
		on their maintenance operations.
Response: The SDT thanks you for your comments. The SDT has developed the Implementation Plan such that it is clear, both to entities and to Compliance Enforcement Authorities, as to when the various requirements must be fully implemented. The Implementation Plan has been crafted to allow entities to systematically implement the standard in a manner that facilitates effective ongoing performance of a PSMP. The SDT does not believe it necessary to "diagram" the PSMP.		
EPRI		The drafting time should see the opinion of the IEEE Stationary Battery Committee before this standard is rolled out for implementation.
Response: The SDT thanks you for your comments. Several members of the NERC Task Force of the IEEE Stationary Battery Committee participated in developing modifications to the sections of Table 1-4 to be more effective and technically accurate.		
ACES Power Marketing Standards Collaborators		1. The first part of definition of a Countable Event should be modified as follows: "The failure of a Component such that it requires repair or replacement...". As it is currently worded, it is technically counting the Component as the Countable Event and not the failure of the component. Considering that the other two items that are Countable Events are conditions and misoperations, it seems appropriate to make failure the Countable Event. 2. Application of this standard to UFLS is problematic as worded in Section 4.2.2. The UFLS are only applicable if "installed per ERO underfrequency load-shedding requirements". Technically, no UFLS fits this description because there are no ERO requirements to have a UFLS. PRC-006-0 was never approved by the Commission and is not enforceable. The Commission considered it a "fill-in-the-blank" standard. While PRC-006-1 corrects the "fill-in-the-blank" issues and was approved by the NERC BOT November 4, 2010, the Commission has yet to act on it. 3. The data retention requirement for the Protection System Maintenance Program documentation seems excessive. The Data Retention section states that all versions since the last compliance audit must be maintained. Since TOs, GOs,

Organization	Yes or No	Question 4 Comment
		and DPs are all on six year audit cycles, this would require maintaining this documentation for six years. Is this really necessary? The length could become even greater once NERC implements registered entity assessments that could shorten or lengthen the periods between compliance audits. The data retention requirements for Requirements R2, R3, R4, and R5 are not consistent with NERC Rules of Procedure. Section 3.1.4.2 of Appendix 4C - Compliance Monitoring and Enforcement Program states that the compliance audit will cover the period from the day after the last compliance audit to the end date of the current compliance audit. The data retention requirements compel the registered entity to retain documentation for the longer of "the two most recent performances of each distinct maintenance activity for Protection System Components, or all performances of each distinct maintenance activity for the Protection System Component since the previous scheduled audit date". While it may have been intended to apply to both clauses, the "since the previous scheduled audit date" only applies to the second clause. Since some of the maintenance activities have intervals of 12 years, this would require the registered entity to retain documentation for 24 years which cannot be audited since it is outside the audit window per the Rules of Procedures. At a minimum, we suggest clarifying that the documentation must not be maintained past the day after the last audit completion date. In the fourth paragraph of the Data Retention section, Component is not used consistently. It is used in both singular and plural form. It seems like it should be one or the other. 4. Requirement R1 VSLs: For the High VSL, "entities'" should be "entity's" to be consistent with the other VSLs. 5. It is not clear why missing three component types jumps to a Severe VSL. Missing two is a Moderate VSL. Missing three should be a High VSL.

Organization	Yes or No	Question 4 Comment
Response: Thank you for your comments. 1. The SDT agrees with your comments on Countable Event, and has modified the definition of Countable Event to: “A failure of a Component requiring …” 2. Applicability Clause 4.2.2 applies to whatever ERO-required UFLS that may exist, either today or in the future. NERC Reliability Standard PRC-006-1 has now been approved by FERC. 3. The SDT believes that all versions of the entity’s PSMP should be retained for audit purposes. For a Compliance Monitor to be assured of compliance, the SDT believes the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding maintenance to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT specified the data retention in the posted standard to establish this level of documentation, which is consistent with the current practices of several regional entities. 4. The SDT corrected the Requirement R1- High VSL, as you suggested. 5. The SDT believes that missing three components is a “significant percentage,” and is in accordance with the VSL Guidelines.		
Independent Electricity System Operator		The IESO continues to disagree with the VRF assigned to the new R3 and R4. R3 and R4 ask 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/R4 not executable. Hence, we reiterate our position that the VRF for R3 be changed to Medium.
Response: Thank you for your comments. The SDT disagrees, and believes the failure to implement a PSMP should be assigned a VRF of High.		
BAE Batteries USA		The NERC Standard should incorporate suggestions made in a letter provided to the NERC Drafting Team along w/ a specific Task Force Report commissioned by the IEEE Stationary Battery Committee.
Response: The SDT thanks you for your comments. Several members of the NERC Task Force of the IEEE Stationary Battery		

Organization	Yes or No	Question 4 Comment
Committee participated in developing modifications to the sections of Table 1-4 to be more effective and technically accurate.		
Nebraska Public Power District		The SDT believes that it is possible to manage the risks that you describe and that performance of these trip path verifications will be an overall benefit to the reliability of the BES 1. Please provide the basis for the requirement of functional trip checks? 2. Are there recorded instances that an “event” would have been avoided if functional trip checks had been performed? 3. Suggest for monitored microprocessor relays in Table 1-1 and 3 to verify “settings are as specified that are essential to the proper functioning of the protection system”. Many settings are not essential. 4. A key concern is will the reliability of the bulk electric system be affected negatively due to increased risk from human element initiated events as a result of the more frequent functional trip checks that will be required. All functional tests should be moved to the minimum frequency of 12 years to minimize this unknown but present risk.
Response: The SDT thanks you for your comments. 1. Please see Section 15.3 of the Supplementary Reference and FAQ document. 2. While the SDT cannot comment on any specific events that would have been avoided explicitly by performing functional trip checks, there is no doubt that the number of Misoperations will be reduced if more comprehensive maintenance is performed. It is also likely that mal-performance of control circuitry has been a factor in a number of disturbances. 3. In many microprocessor relays, various settings impact other settings, making it difficult to explicitly determine which are essential to proper functioning of the Protection System. Additionally, the SDT anticipates that this activity, for microprocessor relays, may very well be easily performed by downloading the settings from the relay and comparing them to the file of desired settings. 4. The maintenance of the overall control circuitry is already specified for a 12-year interval. Only trip coil verification and lockout		

Organization	Yes or No	Question 4 Comment
relay verification are specified for six years.		
Southwest Power Pool Standards Development Team		Under section 1.3 Evidence Retention we feel like documentation of the last two performances of each distinct maintenance activity should be limited to the last one. This is due to the amount of documentation being recorded as well as for certain a component there is a 12 year maximum interval. Would you have to store this information for 24 years? This could also violate the NERC ruling that was just made on a CAN 008 that stated you do not have to show intervals earlier than June 18th 2007. Suggested alternate language "For Requirement R2, Requirement R3, Requirement R4, and Requirement R5, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the most recent performance of each distinct maintenance activity for the Protection System Components, or all performances of each distinct maintenance activity for the Protection System Component since the previous audit date, whichever is longer, but not prior to June 18th 2007."
Response: The SDT thanks you for your comments. For a Compliance Monitor to be assured of compliance, the SDT believes the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding maintenance to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT specified the data retention in the posted standard to establish this level of documentation, which is consistent with the current practices of several regional entities.		
NextEra Energy, Inc.		1. Verifying electrolyte levels of vented lead acid (VLA) batteries every four (4) calendar months is excessive and will not promote the reliability of the bulk electric system (BES). The maximum maintenance interval should be twelve (12) calendar months. Today's lead-calcium and lead-selenium-low antimony batteries do not experience rapid water loss as compared to the legacy lead-antimony batteries and if battery cells should crack from positive plate growth, twelve (12) calendar months is more than adequate to detect electrolyte leakage before cell failure.

Organization	Yes or No	Question 4 Comment
		2. Verifying that unmonitored communication systems are functional every four (4) calendar months is excessive and will not promote the reliability of the BES. The maximum maintenance interval should be twelve (12) calendar months. Based on our operating experience, twelve (12) calendar months is sufficient to detect communication failures without affecting the reliability of the BES.
Response: The SDT thanks you for your comments. 1. The SDT believes that the four-month interval for checking electrolyte level (absent monitoring) is appropriate, as low electrolyte level may impair the ability of the battery to function properly. 2. The SDT believes that the four-month interval is proper for unmonitored communications systems. The activity related to this interval is to verify basic operating status.		
Flathead Electric Cooperative, Inc.		1. We appreciate the work of the drafting team to fulfill the SAR objectives. Flathead generally does not like some of the new definitions proposed by the revised standard, especially R5, “Unresolved Maintenance Issues” is too vague and will be left up to individual auditors to determine compliance. 2. In addition, it appears the drafting team is creating new definitions for plain English in the definition of Protection System Maintenance Program (PSMP). Surely "test, monitor, inspect, calibrate" don't need NERC definitions. Let's leave the definition as "An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored." Suggest deleting "A maintenance program for a specific component includes one or more of the following activities: o Verify- Determine that the component is functioning correctly. o Monitor - Observe the routine in-service operation of the component. o Test - Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. o Inspect - Detect visible signs of component failure, reduced performance and degradation.

Organization	Yes or No	Question 4 Comment
		o Calibrate-Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement." 3. In addition, it appears the component and component type definitions alter the meaning of the NERC approved definition of a protection system. I would suggest the drafting team not try to redefine the NERC-approved definition of Protection system. 4. "Countable Event" definition seems to conflict with standards related to Misoperation of protection system.

Response: The SDT thanks you for your comments.

1. Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase “demonstrate efforts to correct” (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and yet still be a “closed-end process”). For example, a problem might be identified on a VRLA battery during a six-month check. In instances, such as one that requires battery replacement as part of the long term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects and therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of “Unresolved Maintenance Issue” has been modified to add a clarifying phrase that the deficiency “cannot be corrected during the maintenance interval.” The SDT believes the definition is sufficiently clear, while also allowing some flexibility for both TOs and auditors.
2. The SDT believes that the descriptions within the PSMP definition are necessary so that the definition will be clearly understood and so that entities consistently apply those terms as they implement the activities within the tables.
3. The definitions, for use within this standard, do not alter the approved definition of “Protection System,” but instead provide consistent terms for use within the standard.

Organization	Yes or No	Question 4 Comment
4. The definition, within this standard, of Countable Event has no relationship to the approved definition of Misoperation. It is used solely to describe and evaluate Protection System performance for the purpose of developing and perpetuating a performance-based PSMP.		
Entergy Services		1. We recommend the word “Protection” be deleted from the definition of Component to make the defined term Component be a generic term. If that word is not deleted then we recommend the term used in the standard “Protection System Component” be changed to “Component” since as defined a Component is a Protection System piece of equipment. Component - A Component is any individual discrete piece of equipment included in a System, including but not limited to a protective relay or current sensing device. 2. The designation of what constitutes a control circuit Component is dependent upon how an entity performs and tracks the testing of the control circuitry. Some entities test their control circuits on a breaker basis whereas others test their circuitry on a local zone of protection basis. Thus, entities are allowed
Response: The SDT thanks you for your comments. 1. The SDT intends that the term not be generic, and that term explicitly apply within this standard. 2. The intent of the different means of identifying control circuitry was to accommodate various entities’ philosophies on testing these circuits. Regardless of how an entity chooses to identify their control circuitry, the entity must meet the requirements of the standard regarding maintenance of control circuitry.		
PNGC Comment Group		We thank the SDT for their hard work and will be voting "yes" on this project. However, we have 5 specific comments independent of the questions above and we've listed them in order of priority: 1. The PNGC Comment Group takes issue with the associated VSLs for R3. For a small entity using a time based maintenance program, even one missed interval could be enough to elevate them to a high VSL despite the limited impact on the Bulk Electric

Organization	Yes or No	Question 4 Comment
		System. Consider an entity with 9 total components within a specific Protection System Component Type. One violation would mean an 11% violation rate, enough to catapult them into a High VSL. Given the "NERC Guidance (Below), this seems to be a contradiction given the language of "...more than one". a. NERC Guidance on VSL assignment: i. LOWER: Missing a minor element (or a small percentage) of the required performance ii. Moderate: Missing at least one significant element (or a moderate percentage) of the required performance. iii. High: Missing more than one significant element (or is missing a high percentage) of the required performance or is missing a single vital component. iv. Severe: Missing most or all of the significant elements (or a significant percentage) of the required performance. We suggest changing the language for "Lower VSL" for R3 to: For Responsible Entities with more than a total of 20 Components within a specific Protection System Component Type in Requirement R3, 5% or fewer have not been maintained... OrFor Responsible Entities with a total of 20 or fewer Components within a specific Protection System Component Type, 2 or fewer Components in Requirement R3 have not been maintained... 2. The PNGC comment group disagrees with the "Evidence Retention" requirements for the standard. In the current version for R2-R5, entities are required to: "...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 the previous scheduled audit date, whichever is longer." The PNGC comment group believes that keeping documentation for one previous maintenance activity or since the last audit, whichever is longer, should be sufficient. Keeping the two most recent instances of an activity with a maximum maintenance interval of 12 years could mean planning for up to 35 years or so of evidence retention. With the longer of "since the last audit" or "at least one maintenance interval" as the minimum retention requirement the CEA should have sufficient basis to determine compliance. 3. The PNGC comment group believes R5, "Unresolved Maintenance Issues" is too

Organization	Yes or No	Question 4 Comment
		vague and will be left up to individual auditors to determine compliance. This requirement appears ripe for misapplication and future CANs on the topic. Good utility practice will ensure that maintenance issues are corrected as a primary function of our members is to provide the most reliable service possible. The SDT lists several possible examples of evidence in M5 but we believe that more specificity is needed for evidence requirements or the requirement should be removed. We understand the importance of "maintenance" of protection systems and that when maintenance issues cannot be immediately addressed there needs to be follow up. We believe notation of the maintenance issue during the inspection should be sufficient for compliance. By including the examples in the associated measure for the requirement, we believe the SDT has confused the issue. In our opinion M5 should indicate that evidence of notation of the issue is all that is required (meaning acknowledging of the issue on the inspection form). Further, in your response to entity comments during the last comment period on this topic, you stated, "The SDT believes that an effective PSMP must include correction of deficiencies...". This statement implies that the standard must cover the correction of deficiencies to completion. There could be very long time frames associated with maintenance including management budget decisions, equipment purchase lead times and personnel scheduling for follow up work. Some issues could potentially require years of tracking within this standard creating an unnecessary compliance risk for the entity. We believe the SDT has met the intent of order 693 if a maintenance activity is initiated. The completion of the initiated maintenance activity should be outside the bounds of the standard and the standard should clearly state this. 4. We also find issues with the "Definitions of Terms Used in Standard "Specifically, the definition of "Component" seems to confuse the subject unnecessarily. We suggest simplifying the definition by breaking out the control circuitry and voltage and current sensing device examples. That is a lot of material to cover in what should be a simple definition of "Component". 5. Also we believe the definitions of the 5 behaviors under the PSMP definition are

Organization	Yes or No	Question 4 Comment
		unnecessary. We believe that indicating that the PSMP involves some or all of the 5 activities without trying to define them is fine. For example, your definition of "Inspect" states: Detect visible signs of component failure, reduced performance and degradation. But what if you find no failure, reduced performance or degradation? Have you not inspected the component? Or what about "verify"? If you determine the component is not functioning correctly, have you not verified anything?

Response: The SDT thanks you for your comments.

1. A smaller entity will have less to maintain in accordance with the standard; and, thus, the percentages are still appropriate.
2. For a Compliance Monitor to be assured of compliance, the SDT believes the Compliance Monitor will need the data of the most recent performance of the maintenance, as well as the data of the preceding maintenance to validate that entities have been in compliance since the last audit (or currently, since the beginning of mandatory compliance). The SDT specified the data retention in the posted standard to establish this level of documentation, which is consistent with the current practices of several regional entities.
3. Management of completion of the identified unresolved maintenance issue is a complex topic that falls outside of the scope of this standard. There can be any number of supply, process and management problems that make setting repair deadlines impossible. The SDT specifically chose the phrase "demonstrate efforts to correct" (with guidance from NERC Staff) because of the concern that many more complex unresolved maintenance issues might require greater than the remaining maintenance interval to resolve (and yet still be a "closed-end process"). For example, a problem might be identified on a VRLA battery during a six-month check. In instances such as one that requires battery replacement as part of the long term resolution, it is highly unlikely that the battery could be replaced in time to meet the six-calendar-month requirement for this maintenance activity. The SDT does believe corrective actions should be timely, but concludes it would be impossible to postulate all possible remediation projects; and, therefore, impossible to specify bounding time frames for resolution of all possible unresolved maintenance issues or what documentation might be sufficient to provide proof that effective corrective action is being undertaken. The definition of "Unresolved Maintenance Issue" has been modified to add a clarifying phrase that the deficiency "cannot be corrected during the maintenance interval." The evidence listed in the Measure is intended to be illustrative of the types potentially effective evidence, but is not all-inclusive, as demonstrated by the term, "… not limited to…"
4. The definitions of terms that are specified for use only within this standard are intended to support consistent application of the

Organization	Yes or No	Question 4 Comment
standard. 5. The SDT believes that the descriptions within the PSMP definition are necessary so that the definition will be clearly understood and so that entities consistently apply those terms as they implement the activities within the tables. The term "inspect" was modified to "Examine for …" in consideration of your comment.		
Western Area Power Administration		Western Area Power Administration - Rocky Mountain Region does not agree with changing lockout devices to 6 year intervals for testing.
Response: The SDT thanks you for your comments. The interval for lockout relays has been at six years for several drafts; this is not a change. The SDT believes that electromechanical lockout relays need periodic operation, and that six years is the appropriate interval. Performance-based maintenance is an option, if you want to extend your intervals beyond six years.		

END OF REPORT