Consideration of Comments on Draft Standard Version 1 Protection System Maintenance and Testing — Project 2007-17

The Protection System Maintenance and Testing SDT thanks all commenters who submitted comments on PRC-005-2 — Protection System Maintenance standard. This standard was posted for a 45-day public comment period from July 24, 2009 through September 8, 2009. Stakeholders were asked to provide feedback on the Standard through a special electronic comment form. There were 57 sets of comments, including comments from more than 130 different people from over 75 companies representing all of the 10 Industry Segments as shown in the table on the following pages.

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

The SDT proposed to change the name of the draft standard from "Protection System Maintenance and Testing" to "Protection System Maintenance", and to include testing as one component of "Protection System Maintenance Program", which will be a defined term. The majority of stakeholders agreed with both the change in the name of the draft standard and with the definition of Protection System Maintenance Program. Only two respondents disagreed and their comments were addressed. Hence, the draft standard will now be referred to as "Protection System Maintenance."

Stakeholders generally disagreed with the minimum maintenance activities as well as the maximum allowable intervals included in Tables 1a, 1b, and 1c in the draft standard. As a result, the SDT made extensive changes to the standard and tables regarding the maintenance activities, and made minor changes relative to the associated maintenance intervals.

A majority of the respondents agreed with the general approaches regarding condition-based and performance based maintenance programs but provided suggestions on improving the clarity of the provisions within the tables and expressed concerns about perceived administrative issues in establishing the programs. The SDT responded by revising the tables to improve clarity and addressing the administrative concerns in its responses to comments.

Stakeholders expressed appreciation for the "Supplementary Reference Document" and the "Frequently-asked Questions" (FAQs) document. In its responses to the comments, the SDT explained the relationship between the Standard and the two documents. Additionally, the SDT addressed many of the comments in Questions 1-5 by developing additional FAQ content, and referring the respondents to the FAQs document.

Most stakeholders were unaware of any conflicts between the proposed standard and any business practices; however, a few commented that conflicts possibly existed with existing business practices or with other organizations such as the Nuclear Regulatory Commission. The SDT provided clarifying explanations to illustrate that conflicts are not actually present.

Stakeholders made numerous comments and suggestions resulting in substantial changes to the draft Standard, the Supplemental Reference Document, the FAQs, and minor changes to the draft Implementation Plan.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards,

Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

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

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

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Joe Spencer - SERC staff	SERC Protection and Controls Sub-committee (PCS)										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Paul Nauert	Ameren Services Co.	SERC	1, 3, 5
2.	Rick Conner	E.ON Services Inc.	SERC	1, 3, 5, 6
3.	Charles Fink	Entergy	SERC	1, 3, 5, 6
4.	Phil Winston	Georgia Power Co.	SERC	1, 3, 5
5.	Steve Waldrep	Georgia Power Co.	SERC	1, 3, 5
6.	Jay Farrington	PowerSouth Energy Coop.	SERC	1, 3, 5, 6
7.	Jerry Blackley	Progress Energy Carolinas	SERC	1, 3, 5, 6
8.	Marion Frick	South Carolina Electric and Gas Co.	SERC	1, 3, 5, 6
9.	Bridget Coffman	South Carolina Public Service Auth.	SERC	1, 3, 5, 6
10.	George Pitts	TVA	SERC	1, 9, 3, 5
11.	Ron Broocks	Va.Electric and Power Co.	SERC	1, 3, 5
12.	Joe Spencer	SERC Reliability Corp	SERC	10

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
2.	Group	Rick Shackleford	Green Country Energy LLC					X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Danny Parish		SPP	5
2.	Ron Zane		SPP	5
3.	Dennis Bradley		SPP	5
4.	Mike Anderson		SPP	5
5.	Greg Froehling		SPP	5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Brian D. Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Greg Mason	Dynegy Generation	NPCC	5
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

19.	Michael Schiavone	National Grid	NPCC	1
20.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
21.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
22.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
23.	Randy MacDonald	New Brunswick System Operator	NPCC	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		SERC	6
2.	Mike Garton		NPCC	5
3.	John Loftis	Electric Transmission	SERC	1
4.	Ron Broocks	Electric Transmission	SERC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Richard Kafka	Pepco Holdings Inc. - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Carlton Bradshaw	Atlantic City Electric	RFC	1
2.	Ken Lehberger	Atlantic City Electric	RFC	1
3.	Randal Coleman	Delmarva Power & Light	RFC	1
4.	Guy Eberwein	Delmarva Power & Light	RFC	1
5.	Walt Blackwell	Potomac Electric Power Co	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	David A Szulczewski	Detroit Edison			X	X	X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	David A Szulczewski	Detroit Edison	RFC	
2.	Raju J Vengalil	Detroit Edison	RFC	

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Group	Kenneth D. Brown	Public Service Enterprise Group Companies	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Scott Slickers	PSEG Power Connecticut	NPCC	5
2.	Clint Bogan	PSEG Fossil LLC	ERCOT	5
3.	James Hebson	PSEG ER&T LLC	RFC	6
4.	James Hubertus	PSE&G	RFC	1, 3

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Dean Bender	SPC Technical Svcs	WECC	1
2.	Mason Bibles	Sub Maint and HV Engineering	WECC	1
3.	Laura Demory	PSC Technical Svcs	WECC	1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hohlbaugh	FE	RFC	
2.	Jim Kinney	FE	RFC	
3.	Eric Schock	FE	RFC	
4.	Allen Morinec	FE	RFC	
5.	Ken Dresner	FE	RFC	
6.	Bill Duge	FE	RFC	
7.	Art Buanno	FE	RFC	
8.	Brian Orians	FE	RFC	
9.	Jim Detweiler	FE	RFC	
10.	Ken Bunting	FE	RFC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Carol Gerou	MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6									
2.	Neal Balu	WPS Corporation	MRO	3, 4, 5, 6									
3.	Terry Bilke	Midwest ISO Inc.	MRO	2									
4.	Ken Goldsmith	Alliant Energy	MRO	4									
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6									
6.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6									
7.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6									
8.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6									
9.	Scott Nickels	Rochester Public Utilties	MRO	4									
10.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6									
11.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6									
11.	Group	Deborah Schaneman	Platte River Power Authority Maintenance Group	X		X		X					
	Additional Member	**Additional Organization**	**Region**	**Segment Selection**									
1.	Scott Rowley	Platte River Power Authority	WECC	7									
2.	Gary Whittenberg	Platte River Power Authority	WECC	7									
12.	Individual	James Starling	SCE&G	X		X		X	X				
13.	Individual	Rick Koch	Nebraska Public Power District	X		X		X					
14.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
15.	Individual	Kristina Loudermilk	ENOSERV								X		
16.	Individual	Wade Davis	Otter Tail Power	X									
17.	Individual	Alison Mackellar	Exelon Generation Company, LLC - Exelon Nuclear					X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
18.	Individual	Benjamin Church	NextEra Energy Resources					X					
19.	Individual	Scott Berry	Indiana Municipal Power Agency				X						
20.	Individual	John E. Emrich	Indianapolis Power & Light Co.	X				X					
21.	Individual	Glenn Hargrave	CPS Energy	X		X		X					
22.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
23.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
24.	Individual	Armin Klusman	CenterPoint Energy	X									
25.	Individual	Howard Gugel	Progress Energy	X		X		X					
26.	Individual	John Moraski	BGE	X		X							
27.	Individual	Dale Fredrickson	Wisconsin Electric			X	X	X					
28.	Individual	Frank Gaffney	Florida Municipal Power Agency, and its Member Cities as follows: New Smyrna Beach; City of Vero Beach; and Lakeland Electric	X		X			X				
29.	Individual	Russell C Hardison	TVA	X									
30.	Individual	Kirit Shah	Ameren	X		X		X	X				
31.	Individual	Huntis Dittmar	Lower Colorado River Authority	X									
32.	Individual	Brandy A. Dunn	Western Area Power Administration	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
33.	Individual	Robert Casey	Operations and Maintenance	X									
34.	Individual	Hugh Francis	Southern Company	X		X		X					
35.	Individual	Daniel J. Hansen	RRI Energy					X					
36.	Individual	Silvia Parada-Mitchell	Transmission Owner	X					X				
37.	Individual	Greg Mason	Dynegy					X					
38.	Individual	Michael Ayotte	ITC Holdings	X									
39.	Individual	Robert Waugh	Ohio Valley Electric Corp.	X				X					
40.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
41.	Individual	Danny Ee	Austin Energy	X									
42.	Individual	John Alberts	Wolverine Power Supply Cooperative, Inc.	X		X		X					
43.	Individual	Willy Haffecke	City Utilities of Springfield, MO	X		X		X					
44.	Individual	Charles J. Jensen	JEA	X		X		X					
45.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
46.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
47.	Individual	Scott Barfield-McGinnis	Georgia System Operations Corporation			X	X						
48.	Individual	Jianmei Chai	Consumers Energy Company			X	X	X					
49.	Individual	Vladimir Stanisic	Ontario Power Generation					X	X				

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
50.	Individual	James H. Sorrels, Jr.	AEP	X		X		X	X				
51.	Individual	Jason Shaver	American Transmission Company	X									
52.	Individual	Edward Davis	Entergy Services, Inc	X		X		X	X				
53.	Individual	W. Guttormson	Saskatchewan Power Corporation	X		X							
54.	Individual	Alice Murdock	Xcel Energy	X		X		X	X				
55.	Individual	Martin Bauer	US Bureau of Reclamation					X				X	

1. The SDT proposes to change the name of the draft standard from "Protection System Maintenance and Testing" to "Protection System Maintenance", and to include testing as one component of "Protection System Maintenance Program", which will be a defined term. Do you agree? If not, please explain in the comment area.

Summary Consideration: The majority of the respondents agreed with both the change in the name of the draft standard and with the definition of Protection System Maintenance Program. Some comments were offered, most of which were answered by explanation of the rationale of the SDT.

Organization	Yes or No	Question 1 Comment
US Bureau of Reclamation	No	1. The alteration of the program to include testing as a component does not add value to system reliability. The existing requirement can only be completed with procedures that some of the elements listed under the program. The proposed program is far too restrictive in the manner in which it requires specific actions and thereby excludes others. 2. The program element for monitoring is listed; however, the monitoring is intended to be used through an electronic subsystem and does not allow for observations by experienced technical staff. 3. Testing is listed; however, the definition is limited to the application of signals and precludes other procedures. 4. Further, the definition of Protection System proposed is a nested definition which tends to expand the number of devices covered (any device that has voltage and current sensing inputs) irrespective of their impact on the BPS.
Response: The SDT thanks you for your comments. **1. Maintenance includes a number of actions, one of which is testing; inspections, etc are also part of maintenance. One option is to separately identify each type of activity, another is to combine the types of activities within the overall Maintenance activity and address the specific activity type where relevant. As for including some activities and excluding others, the listed activities are contemplated as minimum activities and do not preclude an entity from performing additional activities.** **2. If a facility is attended, the observation of locally-alarmed conditions by on-site personnel, within the time intervals expressed in the monitoring attributes, can satisfy these requirements. Adequate documentation should be available that the facility is indeed attended, and that the on-site personnel observe the related items. See FAQ V-1-D (page 30)** **3. Nothing is precluded; minimum activities are specified, and entities may use additional approaches.** **4. This concern is addressed by the applicability of the standard, where the applicability is limited to "Protection Systems that are applied on, or are**		

Organization	Yes or No	Question 1 Comment
designed to provide protection for the BES".		
Wolverine Power Supply Cooperative, Inc.	No	Wolverine Power has concern about the level of "prescription" in this standard draft. The intent of the standards is to define what, not how. This draft gets unnecessarily prescriptive in our opinion, particularly in the table
Response: The SDT thanks you for your comments. The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. The SDT has therefore defined the minimum activities necessary to implement an effective PSMP.		
AEP	Yes	
American Transmission Company	Yes	
Austin Energy	Yes	
Bonneville Power Administration	Yes	
City Utilities of Springfield, MO	Yes	
Consumers Energy Company	Yes	
CPS Energy	Yes	
Detroit Edison	Yes	
Duke Energy	Yes	
Dynegy	Yes	
ENOSERV	Yes	
Entergy Services, Inc	Yes	

Organization	Yes or No	Question 1 Comment
Florida Municipal Power Agency, and its Member Cities	Yes	
Georgia System Operations Corporation	Yes	
Green Country Energy LLC	Yes	
Illinois Municipal Electric Agency	Yes	
Indiana Municipal Power Agency	Yes	
Indianapolis Power & Light Co.	Yes	
ITC Holdings	Yes	
Lower Colorado River Authority	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
NextEra Energy Resources	Yes	
Northeast Power Coordinating Council	Yes	
Ohio Valley Electric Corp.	Yes	
Oncor Electric Delivery	Yes	
Ontario Power Generation	Yes	
Operations and Maintenance	Yes	

Organization	Yes or No	Question 1 Comment
Otter Tail Power	Yes	
PacifiCorp	Yes	
Pepco Holdings Inc.	Yes	
Platte River Power Authority Maintenance Group	Yes	
Progress Energy	Yes	
Public Service Enterprise Group Companies	Yes	
RRI Energy	Yes	
Southern Company	Yes	
Transmission Owner	Yes	
TVA	Yes	
Western Area Power Administration	Yes	
Wisconsin Electric	Yes	
Xcel Energy	Yes	
FirstEnergy	Yes	Although we agree with the change in the title of the standard, as well as the proposed definition of "Protection System Maintenance Program", we feel that the definition could be clarified. With regard to "Restoration", which at present is described as "The actions to restore proper operation of malfunctioning components", it may be helpful to add examples of acceptable actions to restore operations, such as calibration, repair, replacement, etc.

Organization	Yes or No	Question 1 Comment
Response: The SDT appreciates your support and comments. An FAQ document is included that addresses your comment related to an example of acceptable operations to restore operations. See FAQ II-2-B. (page 5)		
JEA	Yes	Generally agree; however, some suggestions for possible changes: 1) change "associated communication systems necessary for correct operation of protective devices" to "protective relays", 2) add a PSMP glossary definition for an acceptable type of monitored alarm, either to the proposed "PSMP monitor" or another definition for "PSMP monitored and alarmed." The SDT did a good job of making the overall Protection System definition clearer.
Response: The SDT appreciates your support and comments. **1) "Protective relays" is too specific a term here; it excludes applications such as logic-based direct transfer trip that provides protective functions.** **2) The SDT disagrees that the proposed definition is necessary. Guidance on this issue is included in the FAQ. See FAQ V-1-A (page 28)**		
MRO NERC Standards Review Subcommittee	Yes	N/A
Exelon Generation Company, LLC	Yes	None
Saskatchewan Power Corporation	Yes	Saskatchewan would like clarification of what the expectations and rationale are for including Restoration in the PSMP. The other terms listed under the PSMP definition represent what we would consider as typical relay maintenance activities. We would typically consider Restoration as an Operational activity. The existing NERC standards seem to treat this as an Operator concern addressed in PRC-001 R2.1 and R2.2 (The Operator shall take corrective action as soon as possible). If Restoration is included in PRC-005 doesn't PRC-001 have to be modified as well to remove these references? Saskatchewan would also like clarification on the term upkeep. Is the standard prescriptive and mandate the application of the latest firmware upgrades within a defined period, or is it flexible and can upgrades be applied as the utility deems necessary?
Response FAQ II-2-B (page 5) explains that restoration is the "corrective activities necessary to assure that the component is returned to working order following the discovery of its failure or malfunction" and provides extensive discussion contrasting "restoration" in this context from "restoration" in a system operations context. Examples are also discussed. Note that the word, 'restoration' is capitalized in the definition, but this capitalization is for consistent format by capitalizing the first letter of each word in each bulleted phrase – the word was not capitalized to show that		

Organization	Yes or No	Question 1 Comment
the term is using the approved definition of 'Restoration.'		
SCE&G	Yes	The SDT is to be commended for developing a clear and well documented draft. Overall it provides a balanced view of Protection System Maintenance, and good justification for its maximum intervals.
Response: The SDT appreciates your support.		
Ameren	Yes	1. We commend the SDT for developing such a clear and well documented first draft. It generally provides a well reasoned and balanced view of Protection System Maintenance, and good justification for its maximum intervals. Our existing M&T Program has and continues to yield a very reliable BES with mostly similar intervals, though some are longer and others shorter. We strongly support the almost all of the applicability revision, which clarifies the boundary of NERC maintenance and testing oversight. 2. We question the addition of UFLS station DC Supply, auxiliary relays, and Generating facility system-connected station service transformers. Have these components been a significant source of problems leading to cascading outages? 3. The SDT also modifies the Protection System definition, mostly clarifying the boundaries. We generally agree except that we recommend adding "fault" before "interrupting devices".
Response: **1. The SDT appreciates your support and comments.** **2. The standard is not focused only on causes of "cascading outages"; it is focused on "Protection Systems that are applied on, or are designed to provide protection for the BES" and on maintenance of the UFLS systems. The components addressed in the comment are all part of the BES, or the UFLS. As for the DC supply to the UFLS, it is a component that is necessary for the UFLS to function properly. FAQ II-4-D (page 11) discusses what auxiliary tripping relays are actually included, and FAQ III-2-A (page 20) provides a discussion of station service (auxiliary) transformers and their inclusion in this standard.** **3. The "Interrupting devices" is a term that addresses the actions of UFLS, UVLS, and SPS, as well as the actions to clear faults.**		
Electric Market Policy	Yes	We commend the SDT for developing such a clear and well documented first draft. In general, it provides a well reasoned and balanced view of Protection System Maintenance.
Response: The SDT appreciates your support.		
SERC (PCS)	Yes	We commend the SDT for developing such a clear and well documented first draft. It generally provides a well reasoned and balanced view of Protection System Maintenance, and good justification for its maximum

Organization	Yes or No	Question 1 Comment
		intervals.
Response: The SDT appreciates your support		
AECI	Yes	
Puget Sound Energy	Yes	

2. Within Table 1a, Table 1b, and Table 1c, the draft standard establishes specific minimum maintenance activities for the various types of devices defined within the definition of "Protection System". Do you agree with these minimum maintenance activities? If not, please explain in the comment area.

Summary Consideration: Most of the respondents disagreed with the minimum maintenance activities to some degree or another. The disagreement ranged over the full spectrum of activities specified in the Tables, resulting in numerous changes to the standard in response to comments.

Organization	Yes or No	Question 2 Comment
ITC Holdings	No	1. (FAQ 3C) What is the technical justification for omitting insulation testing of the wiring for DC control, potential and current circuits between the station-yard equipment and the relay schemes? We feel this wiring is susceptible to transients which, over time, may compromise the insulation, and therefore should be tested. 2. 2. Table 1a (Page 6) Improve wording. Suggestion: "Verify proper functioning of the current and voltage circuits from the voltage and current sensing devices to the protective relay inputs" 3. On Page 6: The red light monitors trip circuit not only trip coil. With only one circuit going to three parallel single-pole trip coils a red light will not detect a single open trip coil. Is a station inspection that verifies the red light is "on" an acceptable activity? 4. On Page 9: The 3 month communications maintenance activities should say that the channel needs to be checked. For example: initiate a manual checkback test of the carrier system. 5. On Page 10: Not clear on level 2 monitoring attributes for protective relay component description. As written it notes two separate requirements which are ambiguous. We assume that all monitoring noted is required (internal self diagnosis and waveform sampling)? 6. On Page7: The standard should note that battery testing must include all batteries that are used in protective relay systems (for example pilot wire batteries).
Response: The SDT thanks you for your comments. **1. The SDT does not believe that insulation testing needs to be included within the minimum required maintenance activities; the SDT is not aware of a body of evidence that suggests that these tests should be included as a requirement. The proposed standard does not prevent an entity from including such tests in its program if its experience indicates that such testing is needed.** **2. The SDT has modified the standard in consideration of your suggestion and the suggestions of others as shown:**		

Organization	Yes or No	Question 2 Comment
Verify proper functioning of the current and voltage circuit signals necessary for Protection System operation from the voltage and current sensing devices to the protective relays. **3. The SDT has modified the standard to remove the requirement cited in this comment as shown below:** **4. The SDT has modified the standard in consideration of your suggestion as shown below:** Verify that the Protection System communications system is functional. **See FAQ II-6-B for suggestions related to methodology.** **5. Yes. For level 2 monitoring, all attributes must be satisfied. The SDT has modified the standard to clarify as shown below:** Includes: • Internal self diagnosis and alarm capability • Alarm must assert for power supply failures. • Input voltage or current waveform sampling three or more times per power cycle • Conversion of samples to numeric values for measurement calculations by microprocessor electronics that are also performing self diagnosis and alarming. **6. The proper functioning of such batteries will be addressed by the verification and monitoring of the communications system, and by addressing maintenance correctable issues related to the communications system.**		
Green Country Energy LLC	No	1) Protection System Control Circuitry (Trip Circuits) (except for UFLS or UVLS) also The maintenance activity causes excessive breaker operation, and the intrusive nature increases the risk of subsequent misoperations on operating units. System configuration of many plants will require an extensive interruption of total plant production to complete the test. 2) Protection System Control Circuitry (Trip Circuits) (UFLS or UVLS systems only) The maintenance activity causes excessive breaker operation, and the intrusive nature increases the risk of subsequent misoperations on operating units. System configuration of many plants will require an extensive interruption of total plant production to complete the test.
Response: The SDT thanks you for your comments. **1. The overall Protection System Control Circuitry can be addressed in segments, as long as all portions are verified or tested as required. Depending on the arrangement of the DC control circuit, it may be necessary to only trip the breaker itself once. See FAQ II-4-E. (page 11)** **2. The overall Protection System Control Circuitry can be addressed in segments, as long as all portions are verified or tested as required.**		

Organization	Yes or No	Question 2 Comment
Depending on the arrangement of the DC control circuit, it may be necessary to only trip the breaker itself once. See FAQ II-4-E. (page 11)		
Public Service Enterprise Group Companies	No	1) Table 1a Protection System Control Circuitry (Trip Circuits) (UFLS/UVLS Systems Only). Currently, we test our UFLS relays on a 2 year maintenance interval. We test the relays and associated DC circuitry up to the DC lockout relays. It would require extraordinary effort to trip the breakers directly when performing these tests. Usually, each UFLS relay will trip several feeder breakers. This requirement states that we need to check the trip coil for each of those breakers each time we perform relay maintenance. This will add an unreasonable amount of time and effort to reliably switch out several 4kV or 13kV feeders every time we perform UFLS maintenance. For UFLS and UVLS schemes, we feel the requirement for DC control testing should not go past the lockout relay. The standard says to perform trip checks at the same time as UF maintenance. We test the relays on a 2 year interval right now. It is unreasonable to perform trip checks this often. The trip checks should follow a 6 year span (or longer) just like the BES equipment. 2) Table 1a DC supply. The 18 month inspection requires a measurement of specific gravity and temperature. We believe that if a battery owner opts to perform an 18 month ohmic value test, this combined with the cell voltage readings and continuity tests will give a good indication of battery health. We do not feel that the measurement of specific gravity is required in conjunction with the tests performed above.
Response: The SDT thanks you for your comments. **1. The SDT has modified the standard in consideration of your comment as shown below:** Perform a complete functional trip test that includes all sections of the Protection System control and trip circuits, including all electromechanical trip and auxiliary contacts essential to proper functioning of the Protection System, except that verification does not require actual tripping of circuit breakers or interrupting devices. **See FAQ II-8-D (page 19) for a discussion on this.** **2. The SDT has modified the standard in consideration of your comment and this has been deleted.**		
Wisconsin Electric	No	1. Page 7 Station DC Supply (Batteries): The activity to verify proper electrolyte level should only apply to unstaffed (unmanned) stations; checking battery electrolyte levels is routinely done in generating stations, which are staffed with personnel continuously (24 x 7). In addition, the three activities listed here with a 3 month interval for batteries (electrolyte, voltage, grounds) should NOT require documentation for compliance purposes. It should be sufficient that these routine and recurring activities (every 3 months) are identified in the Maintenance Plan. Otherwise the administrative burden to provide documentation will become excessive and counterproductive to assuring BES reliability. 2. Page 7 Station DC Supply (Batteries): The 18 month interval includes an activity to verify the battery charger equalize voltage. This activity is normally done only when the bank is load tested. Therefore the

Organization	Yes or No	Question 2 Comment
		activity to verify equalize voltage of a charger should have a 6 year interval along with the other battery charger activities to verify full rated current and current-limiting. 3. Page 9 Communications Equipment: Similar to #1 above, the activity to verify monitoring and alarms should NOT require documentation in order to demonstrate compliance. Having these routine 3 month activities in the Maintenance Plan is sufficient. This needs to be clarified in the standard. Also, this requirement should be re-worded to refer to generating stations also, not just substations. 4. Page 11 Station DC Supply (Batteries): Like #1 above, the similar requirement in Table 1b for verifying battery electrolyte levels should be revised to indicate that documentation is NOT required. 5. Page 6 Prot System Control Circuitry: Like #1 above, the 3 month activity to verify continuity of breaker trip circuits is fine, but there should be no requirement to document the readings or observations; it is sufficient that this activity be addressed in the Maintenance Plan, especially for staffed generating stations. 6. Page 6 Prot System Control Circuitry: For the 6 year activity to "perform a functional trip test...": is this a requirement to actually trip the circuit breaker ? If yes, this should be stated clearly in the Maintenance Activity description. 7. We are concerned that the Maintenance Activities are not appropriate for certain equipment. The RFC definition of Bulk Electric System includes any protection equipment that can trip a BES facility independent of voltage level. As an LSE, this includes distribution-level equipment that was not designed to the same level of redundancy as Transmission equipment. Complying with the requirements for control circuitry functional testing and current sensing device testing will actually decrease system reliability since this often cannot be accomplished without requiring outages to major distribution system components and/or temporarily breaking protection circuits. We propose that this type of testing on distribution systems which fall under the definition of BES Protection Systems should be addressed separately from the rest of the BES Protection Systems in this standard. The intervals and/or maintenance activities should reflect the differences in how these distribution protection systems are designed and operated.

Response: The SDT thanks you for your comments.

1. **The SDT has modified the standard in consideration of your comment. The revised standard requires the responsible entity to "check" the following every 3 calendar months:**
   - Electrolyte level (excluding valve-regulated lead acid batteries)
   - Station dc supply voltage
   - Unintentional grounds

2. The SDT has modified the standard in consideration of your comments regarding DC supply and the reference to "equalize voltages" has been

Organization	Yes or No	Question 2 Comment
removed **3. The word "substation" has been removed from this requirement. Documentation of completion of required maintenance activities will likely be necessary to demonstrate compliance.** **4. The SDT has modified the standard in consideration of your comments to require checking of electrolyte levels, instead of verification. Documentation of completion of required maintenance activities will likely be necessary to demonstrate compliance.** **5. The SDT has modified the standard to remove the requirement cited in your comment.** **6. Yes. The intent here is that the entire dc control circuit, including the breaker trip coil, be exercised. This was changed to read as follows:** Perform a complete functional trip test that includes all sections of the Protection System control and trip circuits, including all electromechanical trip and auxiliary contacts essential to proper functioning of the Protection System. **7. As established in 4.2.1, this standard applies to all Protection Systems that are "Protection Systems that are applied on, or are designed to provide protection for the BES".**		
Exelon Generation Company, LLC	No	1. Minimum maintenance activities should be on a yearly multiplier verses a monthly multiplier. Nuclear generating stations are typically on an 18-month or 24-month refueling cycle. The draft standard does not take into consideration a nuclear generators refueling cycle. Specifically, most Boiling Water Reactors (BWRs) are on a 24-month refueling cycle and may run continuously between refueling outages. Performing maintenance on-line puts the generating unit at risk without any commensurate increase in reliability to the bulk electric system. 2. All maintenance activities should include a "grace" period to allow for changes to a nuclear generator's refueling schedule and emergent conditions that would prevent the safe isolation of equipment and/or testing of function. "Grace" periods align with currently implemented nuclear generator's maintenance and testing programs. 3. Activities that begin with "verify" should be modified to "Validate…are/is within acceptable limits. Initiate corrective actions as required." For example, some levels of DC grounds are acceptable based on circuit design and component installation. Troubleshooting or ground isolation may increase the risk to the system depending on ground magnitude and conditions. 4. Please provide clarification on "verify that no dc supply grounds are present" most stations have some level of ground current. Should this be interpreted to be a measure of resistance or current values? Suggest rewording to say "Check and record unintentional battery grounds" 5. "Verify Station Battery Chargers provides the correct float and equalize voltage" should be deleted. Equalizing a battery is a maintenance function and should only be performed as needed. Suggest rewording

Organization	Yes or No	Question 2 Comment
		to say "Check and record charger output current and voltage." 6. Activities associated with Battery Charger performance should be deleted. The ability of the Battery Charger to maintain the battery at full charge state is verified by checking proper "float voltage." The ability to provide full rated current only affects the ability to recharge a battery AFTER an event has occurred. 7. In Table 1a does the requirement to "verify proper electrolyte level" refer to all batteries or only a sampling? Current practice is to use the "pilot cell" as the monitoring cell as this cell is usually the least healthy of the battery bank from a specific gravity and/or voltage standpoint. If the pilot cell continues to degrade then the other batteries will be monitored more often. Suggest rewording to "Check electrolyte level." 8. In Table 1a the 18-month requirement to measure that the specific gravity and temperature of each cell is within tolerance is "where applicable" what does "where applicable" mean? 9. For the Station dc supply (battery is not used) 18-month interval should this be interpreted that it is just the battery charger with no attached battery? Or a dc supply system that does not contain a battery? 10. Table 1a Station dc supply 18-month interval to verify cell-to-cell and terminal connection resistance is within "tolerance" should be revised to say "tolerance or acceptable limits." 11. Table 1a Station dc supply (that has as a component valve regulated lead-acid batteries) should provide an additional optional activity for "Total replacement of battery at an interval of four (4) years" in lieu of not conducting performance or service capacity test at maximum maintenance interval.

Response: The SDT thanks you for your comments.

1. The activities that are on an interval less than one calendar year are all "inspection" type activities, rather than "testing" activities. The SDT requests more specificity as to your concerns.

2. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8.4 of the Supplementary Reference Document (page 13) and FAQ IV-2-D (page 23) for a discussion on this issue.

3. The SDT has modified the standard and Frequently Asked Questions document (See FAQ II-5-I, page 15) in consideration of your comments about dc grounds.

4. The SDT has modified the standard and Frequently Asked Questions document (See FAQ II-5-I, page 15) in consideration of your comments about

Organization	Yes or No	Question 2 Comment
no dc supply grounds being present. The language in the standard was changed to: Check for unintentional grounds **5. The SDT has modified the standard in consideration of your comments – the phrase, “equalize voltages,” was deleted** **6. The performance of the battery charger is critical to the performance of the protection system. The SDT has modified the standard to simplify the requirements related to maintenance of the battery charger.** **7. The SDT has modified the standard in consideration of your comments. The Maintenance Activity related to electrolyte level of batteries has been changed from “verify proper” to “check” electrolyte levels. This Maintenance Activity refers to every individual cell in a non-VLRA station battery, similar to recommendations in the relevant IEEE Standards.** **8. The SDT has modified the standard in consideration of your comments. The requirement to measure that the specific gravity and temperature of each cell is within tolerance is "where applicable" has been deleted.** **9. The FAQ II-5-A (page 12) addresses your question concerning “Station dc supply (battery is not used)” by explaining that “a Station dc supply where a battery is not used” is a situation where another energy storage technology besides a battery is used prevent loss of the station dc supply when ac power to the station dc supply is lost.** **10. The SDT has modified the standard in consideration of your comments regarding cell-to-cell and terminal connection resistance – the phrase, “within tolerance” was deleted – and the requirement was subdivided to clarify that the entity must “verify battery terminal connection resistance and verify battery cell-to-cell connection resistance.”** **11. The SDT believes that the maintenance activities specified in Table 1a for VRLA batteries are necessary to assure that the station battery will perform reliably and that replacement of the battery every four years in lieu of such testing would not provide such assurance. The SDT is providing the option of either capacity testing (every three years) or measuring individual cell/unit ohmic values (every three months) and trending the test results against the station battery’s baseline to allow entities to choose which of these activities best address their facilities. Total replacement of a VRLA battery with a properly-performing new battery, 3 calendar years after installation of the original battery, is in compliance with Table 1a of this standard. See FAQ IV-2-A (page 22) & IV-2-B (page 23) for a discussion about commissioning tests and how they relate to establishing a baseline.**		
US Bureau of Reclamation	No	1. The basis for developing the maintenance intervals was adequately explained. It is understood that FERC would like uniform intervals; the intervals do not recognize the tremendous variation in installation and equipment and possibly manufacturer recommendation. Point in fact is the interval for listed for electromechanical relays. Some of these relays must be calibrated every year or three years on the outside. Relays that have a history of stable performance based on consistently good test results. 2. The intervals for battery maintenance are not reasonable. The capacity testing at 3 years is higher than the 5 year which battery manufactures require.
Response: The SDT thanks you for your comments. **1. The proposed standard does not prevent an entity from including such tests in their program if their experience has indicated that such testing is**		

Organization	Yes or No	Question 2 Comment
needed. **2. The 3-year capacity test is specifically for Valve Regulated Lead-Acid batteries (VRLA); Vented Lead-Acid batteries require a 6-year capacity test. Due to the failure mode and designed service life of Valve Regulated Lead-Acid (VRLA) batteries compared to a Vented Lead-Acid batteries, the SDT believes that extending capacity testing of a VRLA battery beyond the maximum maintenance interval of 3 calendar years in Table 1a cannot be justified regardless of what the battery manufacturers recommend.**		
MRO NERC Standards Review Subcommittee	No	A. In the tables, the term “verification” should be switched with “check”. B. The verification activities include testing for “specific gravity” in batteries. Since “impedance testing” will give you the same results or similar results; revise the tables to reflect this, as well. C. Another question deals with the table title verbiage. Table 1a and 1c are labeled as Protection Systems, while Table 1b is Protection System Components. One could interpret table 1c as saying that if any one component of the protection system in question is not in compliance with level 3 monitoring stipulations, then every component must be degraded to level 2 monitoring as so forth. This needs to be clarified. D. Some activities, such as complete functional testing, could lead to reduced levels of reliability, because [1] it requires removing elements of the transmission system from service and [2] it requires performing tests that are inherently prone to human errors. The MRO NSRS does not believe the perceived benefits justify the anticipated costs. E. In the tables, under Table 1a and Protection system communications equipment and channels, a technical justification should be provided to show that performance and quality channel testing would result in the reduction of regional disturbances and blackouts. Quality and performance testing is subjective. Subjective tests are inherently poor compliance measures. The requirements to measure, document, store, and prove channel quality data is a poor use of limited compliance resources. F. In the tables, under Table 1a and Station DC supply (and anywhere else), equalize (battery) voltages should be eliminated. Equalizing battery voltages reduces battery life and do not provide a significant gain in overall system reliability to offset the loss of battery life. G. In the tables, under Table 1a and Station DC supply (and anywhere else), delete the reference to measuring the fluid temperature of “each cell”. A technical basis should be demonstrated that shows why individual cell fluid temperature measurement would reduce the occurrence of regional disturbances. If fluid temperature measurement remains in the standard, a single fluid temperature measurement per battery bank should be sufficient to demonstrate that the battery bank was performing within normal parameters. The compliance burden to add fluid temperature measurements for each cell is unwarranted and reduces compliance personnel resources that could be utilized on more important reliability activities.

Organization	Yes or No	Question 2 Comment
Response: The SDT thanks you for your comments. **A. The SDT has modified the tables in consideration of your comments regarding “verification” vs. “checking”.** **B. The SDT has modified the standard in consideration of your comments – the term, “specific gravity” is not used in the revised standard** **C. The SDT has modified Tables 1a and 1c in consideration of your comments. The subheading of Table 1a and 1c were modified, replacing, “Systems” with “System Components.”** **D. To minimize system impact of such maintenance and possible errors, the maintenance necessarily should be scheduled at a time that minimizes the risks.** **E. Many utilities have long history that emphasizes that maintenance of communications systems is critical to assuring the proper performance of these systems. The intervals were determined based on the experiences of SDT and NERC System Protection and Task Force members. Additionally, this standard is not focused only on avoiding regional disturbances or blackouts, but instead on overall Protection System reliability. See Supplementary Reference Document, Section 15.5 (page 23) and FAQ II-6-D (page 17).** **F. The SDT has modified the standard in consideration of your comments. The requirement to “equalize battery voltages” was removed from the revised standard.** **G. The SDT has modified the standard in consideration of your comments and all references to measuring “temperature” have been removed from the revised standard.**		
CenterPoint Energy	No	a. CenterPoint Energy believes the approach taken by the SDT is overly prescriptive and too complex to be practically implemented. The inflexible minimum “maintenance activities” approach fails to recognize the harmful effects of over-maintenance and precludes the ability of entities to tailor their maintenance program based on their configurations and operating experience. In particular, the loss of maintenance flexibility embodied in this approach would have perverse consequences for entities with redundant systems. Entities with redundant systems have less need for maintenance of individual components (due to redundancy) yet have twice the maintenance requirements under the minimum “maintenance activities” approach. For example, Table 1A calls for performing a specific gravity test on “each cell” of vented lead-acid batteries. CenterPoint Energy believes such a requirement is dubious for entities that do not have redundant batteries, and absurd for entities that do. CenterPoint Energy has installed redundant batteries in most locations and has had an excellent operating history with batteries by using a combination of internal resistance testing and specific gravity testing of a single “pilot cell”. This practice, combined with DC system alarming capability, has worked well. b. CenterPoint Energy is opposed to approving a standard that imposes unnecessary burden and reliability risk by imposing an overly prescriptive approach that in many cases would “fix” non-existent problems. To clarify this last point, CenterPoint Energy is not asserting that maintenance problems do not exist. However,

Organization	Yes or No	Question 2 Comment
		requiring all entities to modify their practices to conform to the inflexible approach embodied in this proposal, regardless of how existing practices are working, is not an appropriate solution. Among other things, requiring entities to modify practices that are working well to conform to the rigid requirements proposed herein carries the downside risk that the revised practices, made solely to comply with the rigid requirements, degrade reliability performance. c. Arguably, an entity could possibly return to its existing practices, if those practices are working well, by navigating through the complex set of options and supporting documentation that the SDT has crafted in this proposal. However, most entities have an army of substation technicians with various ranges of experience to perform maintenance on protection systems and other substation components. It is unrealistic to expect most entities making a good faith effort to comply with this proposal to have a full understanding throughout the entire organization of all the nuances crafted into this complex proposal. d. For the reasons outlined above, CenterPoint Energy does not agree with the proposal to specify minimum maintenance activities. However, if the majority of industry commenters agree with the SDT's proposal, CenterPoint Energy has concerns about some of the proposed tasks. For Protection System control circuitry (trip circuits), Table 1A calls for performing a complete functional trip test. The "Frequently-asked Questions" document states that this "may be an overall test that verifies the operation of the entire trip scheme at once, or it may be several tests of the various portions that make up the entire trip scheme". Such a requirement creates its own set of reliability risks, especially when monitoring already mitigates risks. CenterPoint Energy is concerned with this standard promoting an overall functional trip test for transmission protection systems. This type of testing can negatively impact reliability with the outages that are required and by exposing the electric system to incorrect tripping. CenterPoint Energy views overall functional trip testing as a commissioning task, not a preventive maintenance task. CenterPoint Energy performs such testing on new stations and whenever expansion or modification of existing stations dictates such testing. Overall, CenterPoint Energy recommends minimizing, to the extent possible, maintenance activities that disturb the protection system; that is, placing the protection system in an abnormal state in order to perform a test. e. For Protection System control circuitry (breaker trip coils only), Table 1A calls for verifying the continuity of the trip circuit every 3 months. CenterPoint Energy is not sure what would be the expected task to meet this requirement (it is not addressed in the "Frequently-asked Questions" document).

Response: The SDT thanks you for your comments.

a) The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. Regardless of the level of redundancy provided, all components addressed by this standard must be maintained in accordance with the requirements of the standard. The SDT has therefore defined the minimum activities necessary to implement an effective PSMP. The SDT has modified the standard in consideration of your comments concerning performing a specific gravity test

Organization	Yes or No	Question 2 Comment
and the revised standard does not require a specific gravity test. **b)) The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. The opportunities in R3 provide additional flexibilities for entities which desire them.** **c) For those entities which wish the least complex approach, a pure time-based program, using R1, R2, and R4, with Table 1a provides the simplest approach to meeting this standard.** **d) The SDT believes that functional trip testing is a key component of an effective PSMP.** **e) See the Supplemental Reference Document, Section 15.3 (page 22) for a discussion on this topic.**		
NextEra Energy Resources	No	a. Tables 1a, 1b & 1c should offer as an alternative, measuring battery float voltages and float currents in lieu of measuring specific gravities as described in Annex A4 of IEEE Std 450-2002. b. Inspection of CVT gaps, MOVs and gas tubes should be added to the communications equipment time based maintenance tables. Failure of the CVT protective devices may cause failure of the Protection System. c. Maintenance Activities for UVLS or UFLS station dc supplies shows “Verify proper voltage of dc supply”. Does this imply that, except for voltage readings of the dc supply, distribution battery banks are not maintained? d. Why does the Maintenance Activities for UVLS or UFLS relays state that verification does not require actual tripping of circuit breakers? e. Please clarify the Maintenance Activities for Voltage and Current Sensing Devices. Must voltage, current and their respective phase angles be measured at each discrete electromechanical relay? f. NextEra Energy concurs with other entities comments concerning this question: This entity believes the approach taken by the SDT is overly prescriptive and too complex to be practically implemented. The inflexible “minimum maintenance activities” approach fails to recognize the harmful effects of over-maintenance and precludes the ability of entities to tailor their maintenance program based on their configurations and operating experience. In particular, the loss of maintenance flexibility embodied in this approach would have perverse consequences for entities with redundant systems. Entities with redundant systems have less need for maintenance of individual components (due to redundancy) yet have twice the maintenance requirements under the “minimum maintenance activities” approach. For example, Table 1A calls for performing a specific gravity test on “each cell” of lead acid batteries. Our company believes such a requirement is dubious for entities that do not have redundant batteries, and absurd for entities that do. We have installed redundant batteries in most locations and have had an excellent operating history with batteries

Organization	Yes or No	Question 2 Comment
		by using a combination of internal resistance testing and specific gravity testing of a single "pilot cell". This practice, combined with DC system alarming capability, has worked well. We are opposed to approving a standard that imposes unnecessary burden and reliability risk by imposing an overly prescriptive approach that in many cases would "fix" non-existent problems. To clarify this last point, we are not asserting that maintenance problems do not exist. However, requiring all entities to modify their practices to conform to the inflexible approach embodied in this proposal, regardless of how existing practices are working, is not an appropriate solution. Among other things, requiring entities to modify practices that are working well to conform to the rigid requirements proposed herein carries the downside risk that the revised practices, made solely to comply with the rigid requirements, degrade reliability performance. Arguably, an entity could possibly return to its existing practices, if those practices are working well, by navigating through the complex set of options and supporting documentation that the SDT has crafted in this proposal. However, like many entities, we have an army of substation technicians with various ranges of experience to perform maintenance on protective systems and other substation components. It is unrealistic to expect most entities making a good faith effort to comply with this proposal to have a full understanding throughout the entire organization of all the nuances crafted into this complex proposal. For the reasons outlined above, we do not agree with the proposal to specify minimum maintenance activities. However, if the majority of industry commenters agree with the SDT's proposal, we have concerns about some of the proposed minimum tasks. For Protection System control circuitry (trip circuits), Table 1A calls for performing a complete functional trip test. The "Frequently-asked Questions" document states that this "may be an overall test that verifies the operation of the entire trip scheme at once, or it may be several tests of the various portions that make up the entire trip scheme". Such a requirement creates its own set of reliability risks, especially when monitoring already mitigates risks. We are concerned with this standard promoting an overall functional trip test for transmission Protection Systems. This type of testing can negatively impact reliability with the outages that are required and by exposing the electric system to incorrect tripping. Our company views overall functional trip testing as a commissioning task, not a preventive maintenance task. We perform such testing on new stations and whenever expansion or modification of existing stations dictates such testing.

Response: The SDT thanks you for your comments.

a. The SDT has modified the standard in consideration of your comments. All references to measuring specific gravities have been removed from the revised standard – and for Table 1a for station dc supply, the language was revised to require, "Verify float voltage of battery charger."

b. Power line carrier channels are made up of many components that must be maintained on a periodic basis. This standard indicates that adequate maintenance and testing must be done to keep the performance of the channel at a level that meets the requirements of the relay system. The determination of specific maintenance activities is the responsibility of the Entity.

c. This standard limits the maintenance requirements of distribution system batteries to those used for UVLS and UFLS and constrains those requirements to verification of proper voltage. If "distribution system" batteries are used for any other BES Protection System applications, they must

Organization	Yes or No	Question 2 Comment
be maintained according to the other requirements of this standard. **d. The SDT believes that the UFLS scheme is predominantly based within the distribution sector. As such, there are many circuit interrupting devices that will be operating for any given under-frequency event that require tripping for that event. A failure in the tripping-action of a single distribution breaker will be far less significant than, for example, any single Transmission Protection System failure such as a failure of a Bus Differential Lock-Out Relay. While many failures of these distribution breakers could add up to be significant, distribution breakers are operated often on just fault clearing duty and therefore the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in the standard.** **e. The requirement is that the proper voltage, current, and phase angle must be delivered to each respective relay. The standard does not prescribe methodology. See FAQ II-3-A (page 8) for further discussion.** **f. The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. Regardless of the level of redundancy provided, all components addressed by this standard must be maintained in accordance with the requirements of the standard. The SDT has therefore defined the minimum activities necessary to implement an effective PSMP. The SDT has modified the standard in consideration of your comments concerning specific gravity testing.**		
E.ON U.S.	No	1. Capacity or AC impedance only needs to be done to determine service life and therefore periodic testing of station DC supply does not seem necessary or prudent. 2. If a company checks overall battery bank voltages quarterly then periodic testing of the battery bank charger should not be required.
Response: The SDT thanks you for your comments. 1. **Capacity or Internal Ohmic testing must be periodically performed at the Maximum Maintenance Intervals in Table 1 to verify that a lead acid battery can perform as designed. Periodic testing to ensure that a battery can perform as designed is necessary to ensure that a battery is capable of being a dc source to the station dc loads when required. If a battery fails to perform as designed during test before its designed service life is reached it must be replaced regardless of how many years of service are left on its warranty or its engineered service life.** 2. **Proper functioning of the battery charger is critical to proper performance of the DC supply. The SDT has modified the standard to simplify the battery charger maintenance requirements.**		
City Utilities of Springfield, MO	No	1. CU has concern over the battery charger testing requirements. Per the charger manufacturers recommendations there is no reason to test the chargers as proposed in PRC-005-2. It is their opinion that the chargers are self diagnostic and do not require these tests (full load current and current limiting tests). The charger O&M manuals do not even provide instructions for such tests as optional. Therefore, CU takes exception to this requirement and suggests that battery chargers be maintained and tested in accordance with manufacturer's recommendations.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>2. Additionally, CU is concerned with the wording in Table 1a concerning Protection system communication equipment and channels. We are unsure what the maintenance activity actually means. If this is an unmonitored system, how can you verify the condition of the communication system? Is the standard referring to local monitoring such as enunciators? Please provide clarification.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments.
1. The SDT has modified the standard in consideration of your comments. If the battery charger is self diagnostic, it may qualify for Table 1b or Table 1c.
2. FAQ II-6-A (page 16) provides an extensive discussion about various methods to test communications systems.</td></tr>
<tr><td>Florida Municipal Power Agency, and its Member Cities</td><td>No</td><td>1. FMPA does not believe that maintenance of each UFLS / UFLS systems are as important as maintenance of BES protection systems. The fundamental reason is that delayed or uncleared faults on the BES can cause system “instability, uncontrolled separation, and cascading outages”; therefore, BES protection systems are very important; however, if a small percentage of UFLS / UVLS relays mis-operate as a result of a frequency or voltage event, the impact of the mis-operation is much smaller, if even measurable. As a result, FMPA believes that the emphasis of the maintenance activities ought to be placed on those systems that can have the most impact on what the standards are all about, as Section 215(a)(4) of the Federal Power Act says, “avoiding instability, uncontrolled separation, and cascading outages”. As a result, FMPA believes that full functional testing, while important for BES protection systems, is not necessary for UFLS and UVLS systems (Table 1a, page 6 and Table 1b, page 11). Because most UFLS / UVLS are on radial distribution feeders, such testing will cause outages to customers fed on radial distribution circuits and transmission lines without sufficient cause, in other words, the maintenance itself will reduce the reliability the customer experiences. In addition, distribution tripping circuits are more regularly exercised by distribution faults than are transmission tripping circuits; therefore, full functional testing of distribution tripping circuits is far less valuable than testing trip circuits of transmission elements which are exercised less frequently due to actual system events.
2. FMPA is confused with the wording of Table 1a, page 6, row 3 that talks about breaker trip coils. In the “Type of Component” column, the subject says “Breaker Trip Coils Only (except for UFLS or UVLS)”, yet the maintenance activity described states “Verify the continuity of the breaker trip circuit including trip coil”. These two statements are inconsistent because the first statement limits the applicability to just the trip coil and the second statement goes beyond the trip coil. And, FMPA believes the second statement should only apply to the trip coil, e.g., the second statement should say: “Verify the continuity of the trip coil”. In addition, the parenthetical is confusing, is it meant to say that the continuity of the trip coil only needs to be verified when the breaker operates during the 3 month interval, or that the intended continuity check is from the relay contacts through the trip coil, and not from the relay contacts back to the</td></tr>
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Organization	Yes or No	Question 2 Comment
		batteries? 3. FMPA is also confused concerning station DC supply testing. There are multiple rows in Table 1a concerning various types of testing for various types of batteries and chargers that do not exclude UVLS and UFLS, yet on page 8, on the bottom row, the row is exclusive to UVLS and UFLS yet overlaps other rows discussing station DC supply testing. Is it intended that the other rows that are silent as to what they apply to exclude UVLS and UFLS? FMPA believes that should be the case. The same comment applies to Table 1b. 4. FMPA also has concern over the battery charger testing requirements. Per the charger manufacturers recommendations there is no reason to test the chargers as proposed in PRC-005-2. It is their opinion that the chargers are self diagnostic and do not require these tests (full load current and current limiting tests). The charger O&M manuals do not even provide instructions for such tests as optional. Therefore, FMPA takes exception to this requirement and suggests that battery chargers be maintained and tested in accordance with manufacturer's recommendations
Response: The SDT thanks you for your comments. **1. The SDT believes that UFLS and UVLS maintenance needs to be prescriptive for the following reasons:** **a. PRC-008-0 and PRC-011-0 today require maintenance of UFLS and UVLS equipment.** **b. FERC Order 693 directs NERC to develop maximum allowable intervals for UFLS and UVLS equipment, and recommends combining PRC-005-1, PRC-008-0, PRC-011-0, and PRC-017-0.** **The objectives are not constrained to limiting "instability, uncontrolled separation, and cascading outages", but instead address overall Protection System reliability. The standard has, however, been modified to remove the requirement that the breakers actually be tripped for UFLS and UVLS functional trip testing.** **2. The SDT has modified the standard to remove the requirement cited in your comments.** **3. The SDT has modified the standard to clarify that the only DC Supply requirement relevant to UVLS and UFLS is to verify the DC supply voltage in consideration of your comments.** **4. The SDT has modified the standard in consideration of your comments. If the battery charger is self diagnostic, it may qualify for Table 1b or Table 1c.**		
Indiana Municipal Power Agency	No	IMPA does not agree with the battery charger testing requirements. Per the battery charger manual, the manufacturer sets the current limit at the factory, and it only needs to be adjusted if a lower current limit is desired. The manufacturer gives directions on how to lower the current limiter, and the directions seem to be for this purpose only (not for the sole purpose of performing a current limiter test). The manufacturer also

Organization	Yes or No	Question 2 Comment
		does not give directions on how to perform a full load current test and does not give any recommendation to the user that such test is needed. IMPA believes that both of these maintenance items are not needed to maintain the battery charger and that only the manufacturer's recommendations on maintenance and testing need to be followed.
Response: The SDT thanks you for your comments. The performance of the battery charger is critical to the performance of the protection system. The SDT has modified the standard to simplify the requirements related to maintenance of the battery charger.		
FirstEnergy	No	In general we agree with the maintenance activities, except for the specific gravity and temperature testing included in the "Station dc Supply (that has as a component any type of battery)" of the tables 1a and 1b. We only perform this testing at nuclear facilities for insurance requirements. In transmission substation applications it has been eliminated due to the variability of results due to recharging/equalizing, water addition, temperature correction requirements, etc. In the Supplementary reference, section 15.4 Batteries and DC Supplies, third paragraph, the SDT indicates these tests are recommended in IEEE 450-2002 to ensure that there are no open circuits in the battery string. This is essentially a continuity check of the battery string. In the fourth paragraph, the SDT states that "continuity" was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to the two methods recommended in the IEEE standards."The SDT in Table 1a, the Maintenance Activity "Verify continuity and cell integrity of the entire battery", and in Table 1b, the Maintenance Activity "Verify electrical continuity of the entire battery". Based on the information in the Supplementary reference, the owner has to choose a method to verify continuity and the measurement of specific gravity and cell temperatures could be the selected method, however it should not be a required maintenance activity as shown in Tables 1a and 1b.
Response: The SDT thanks you for your comments and has modified the standard in consideration of your comments. All references to specific gravity and temperature testing have been removed from the revised standard.		
Ohio Valley Electric Corp.	No	1. In general, all maintenance activities that are verifications of proper function imply that problems found must be resolved within the maximum interval. For some activities, that is an unreasonable expectation. A temporary resolution may reliably correct an adverse situation but may not address the original verification requirement within the maximum interval. 2. Routine substation inspections should not fall under NERC standards. The documentation for quarterly inspections would be oppressive. It is unreasonable to require there to be no DC grounds. All DC grounds do not rise to the level of a reliability concern. In some cases, attempting to resolve a relatively minor DC problem may rise to the level of negatively affecting reliability. 3. The value of capacity testing battery banks and chargers in the context of a protection system reliability

Organization	Yes or No	Question 2 Comment
		standard is questionable.
Response: The SDT thanks you for your comments. **1. The SDT has modified the standard to clarify that corrective actions must be initiated, but intentionally does not identify when they need to be completed, largely for the reasons you cite. See FAQ II-2-I (page 7) for a discussion on this.** **2. The SDT believes that certain verification activities must be performed on a periodic basis via visual inspection. The standard and Frequently Asked Questions document (See FAQ II-5-I, page 15) have been modified in consideration of your comment concerning locating and removal of a dc ground. References to dc grounds have been revised to "unintentional dc grounds."** **3. The SDT believes that the ability of the battery to provide required tripping current is CRITICAL to the reliability of the Protection System; else, the Protection System is unable to react properly when required. Similarly, the SDT believes that the ability of the charger to properly charge the battery is critical to sustain the battery capability.**		
AEP	No	In the process of performing maintenance, some protection systems may need to be taken out of service on in-service equipment (bus differential protection for example) where redundant protection systems do not exist. This action seems counter to NERC recommendations, presenting a scenario for expanding outages during a simultaneous fault. Would the implementation plan include time for the additions of redundant protection systems? Comments expanded in question 10 response.
Response: The SDT thanks you for your comments. To minimize system impact of maintenance, the maintenance necessarily should be scheduled at a time that minimizes the risks. The implementation plan addresses the development of acceptable PSMPs.		
RRI Energy	No	1. It is recommended to change the wording of the Maintenance Activities to the activity itself, not the resolved state of the maintenance correctable issue (i.e. "For microprocessor relay, check for proper operation of the A/D converters" instead of "For microprocessor relays, verify proper functioning of the A/D converters"). The wording of the standard effectively sets the end date for the correction of maintenance identified issues. In other words, maintenance has not taken place until all maintenance corrrectible issues have been completely resolved. The wording in the standard have set non-compliance "traps" for those performing the maintenance but have not completed correctable issues for legitimate reasons which may not be allowed by the no-exception approach of the standard. For example, rewording of the Battery Supply 3 month activities are recommended as follows: "Check for proper electrolyte level. Check for proper voltage. Check for dc supply grounds." As inspection activities, any issue not corrected during the interval should become a maintenance correctible issue. For generating stations, the judgments to locate and remove a ground are based upon criteria not accounted for in the requirements of this standard. An activity to locate and clear a ground requires the judgment of station maintenance and operational management depending upon the operating conditions of the unit and the level of the ground (solid or high-resistance).Inspections (3 month requirement

Organization	Yes or No	Question 2 Comment
		activities) although good practices, should not be standard requirements. 2. The practice of verifying the continuity of breaker trip circuits does not belong as an auditable NERC standard requirement; it becomes more of a documentation requirement rather than a reliability improvement. Otherwise, it will ultimately require the expending of resources in an unproductive manner primarily on the development, storage, and production of excessive records for compliance purposes. The elimination of this requirement is recommended. 3. For Table 1a Protection System Control Circuitry - rewording is suggested as follows: "Perform functional trip tests of Protection System trip circuits, including auxiliary relays essential to the proper functioning of the Protection System." The requirement, as presently worded "that includes all sections of the Protection System," is overly prescriptive and will create non-compliances for miniscule oversights, given the very large scope of components in protection systems that are spread out far and wide in a system. The requirement opens the door, allowing the compliance process itself to be punitive in nature. When pursued to the extreme under audit conditions, this requirement will be very difficult to demonstrate on a large scale. 4. For Table 1a Station dc supply: The ability of a battery charger to correctly supply equalize voltage to a battery has no direct correlation to reliability of the BES and does not belong in this standard. The objective is that the battery get an equalize charge when it needs it, not the maintenance of the equalize function of a battery charger. How the battery gets equalized is not important to this standard, especially since a battery and the equalize source are usually disconnected from the protection system during the process. 5. For Table 1a Station dc supply: The use of the term "in tolerance," for the measurement of specific gravity, is an inconsistency in stating the standard requirements. There are multiple activities that will necessitate the measurement of a quantity "in tolerance" whether it is battery charger output, individual cell voltages, connection resistances, or internal ohmic values. The suggested rewording is as follows: "Measure the specific gravity and temperature of each cell." 6. For Table 1a Station dc supply: Referring to the requirement to "verify that the station battery can perform as designed" very little of a generating station battery sizing is related to BES protection. Verification of a generating station to design conditions is outside the scope of BES protection and does not belong in this standard. Nearly all protection system operations operate without reliance upon the battery to do so, and the separation of the generating unit from the BES will take place within cycles, if called upon to do so. The remainder of the battery duty cycle is outside the scope of BES protection.

Response: The SDT thanks you for your comments.

The station dc supply 3 month activities section of table 1a has been reworded in consideration of your comment as shown below:

Check:

Organization	Yes or No	Question 2 Comment
• Electrolyte level (excluding valve-regulated lead acid batteries) • Station dc supply voltage • For unintentional grounds **1. Also FAQ II-5-I (page 15) has been modified in consideration of your comment concerning location and removal of dc grounds on a generating station. The following was added to the FAQs:** In most cases, the first ground that appears on a battery pole is not a problem. It is the unintentional ground that appears on the opposite pole that becomes problematic. Even then many systems are designed to operate favorably under some unintentional DC ground situations. It is up to the owner of the Protection System to determine if corrective actions are needed on unintentional DC grounds. The standard merely requires that a check be made for the existence of Unintentional DC Grounds. Obviously a “check-off” of some sort will have to be devised to demonstrate that a check is routinely done for Unintentional DC Grounds. **Additionally, the Maintenance Activities in Table 1a, Table 1b, and Table 1c have been generally revised as you suggest, to present the activity rather that the resolved state.** **2. The SDT has modified the standard to clarify that this requirement is actually monitoring the trip coil. The SDT believes that verification of breaker trip coil continuity is a vital component of the Protection System performance, and that they must be maintained as specified in the Standard.** **3. The SDT believes that proper functioning of all trip circuit paths is a vital component of the Protection System performance, and that they must be maintained as specified in the Standard.** **4. The SDT has modified the standard in consideration of your comment and the requirement to equalize voltages has been removed from the revised standard** **5. The SDT has modified the standard in consideration of your comment and the comments from others, the reference to measuring specific gravity and temperature has been removed** **6. Thank you for your comments concerning verification that the station battery can perform as designed. Although the SDT agrees with you that very little of a generation station battery sizing is related to BES protection, the majority of a generation station battery duty cycle is for safely operating the station when the other elements of a station dc supply are unavailable and that some Protection System operations can operate using the other elements of the station dc supply besides the station battery. The SDT believes that the station dc supply is such an integral part of the Protection System of a generating station that, at a minimum, it must be maintained using the Maintenance Activities and Maximum Maintenance Intervals of Table 1. It is important to note that the station battery must still be able to perform its vital Protection System functions even if it is simultaneously supplying dc for its myriad of other applications. The required activities include “verify that the station battery can perform as designed.”**		
Indianapolis Power & Light Co.	No	1. Many preventive maintenance programs have testing tolerances which are tighter than the manufacturer’s tolerances. This practice is used to force an action prior to falling outside of the manufacture’s tolerances and

Organization	Yes or No	Question 2 Comment
		accounts for slight variations in test equipment and environment. Maintenance correctable issues should not be reportable unless the test failure falls outside of the manufacturer's published tolerances. 2. In tables 1a through 1c the "Type of Component" columns in each table do not have consistent listings from one 1a to 1b to 1c. The type of component should be identified consistently in each table. By doing so this would eliminate confusion in moving from one table to the other. 3. The maintenance activities for some types of components specifies how (i.e. Test and calibrate the relays. with simulated electrical inputs) while other maintenance activities do not specify how. The maintenance activities should either all be specific or all be generic. 4. For Station dc Supply (that has as a component any type of battery) the maintenance activity of "verify that no dc supply grounds are present" there is a problem of tolerance. It is impossible to have "no dc supply grounds present". There has to be some tolerance given here such as a voltage measurement from each battery terminal to ground +- 15 volts of nominal for example. 5. For the type of component of "Protection System Control Circuitry (trip circuits) (UFLS/UVLS Systems only), the maintenance activity requires a complete functional trip test" of the Protection System. This suggests that a breaker trip test is required at each maintenance interval. This requires tripping breakers that supply customers. It is impossible to trip each individual distribution feeder without forcing an outage on some customers as when there are no other usable circuits to tie the load off to. A failure to trip of a single distribution circuit in the overall scheme of a UVLS or UFLS scheme would have little effect on the BES. Trip testing BES breakers and verifying correct operation of breaker auxiliary contacts could become very difficult to accomplish since opening a breaker on a line might adversely affect the BES. ISOs may prohibit such an activity at any time. Allowances should be made for BES circuit breakers that can not be operated for such reasons if documented sufficiently.

Response: The SDT thanks you for your comments.

1. **The tolerances, per Note 1 to Table 1a, Table 1b, and Table 1c, are defined by the entity according to their application considerations as related to the component. The standard has been revised to exclude minor issues that can be corrected during the on-site maintenance activities from "maintenance correctible issues".**
2. **The variations in the "Type of Component" are a result of the varying maintenance activities that are necessary as there are higher levels of component monitoring. If the "Type of Component" was made consistent among all three tables, there would be additional confusion, because many of the "Types of Component" in Tables 1b and 1c would indicate that no maintenance activities are required.**
3. **Generic activity descriptions have been used except where specific activities are necessary.**
4. **The standard and Frequently Asked Questions document (See FAQ II-5-I, page 15) have been modified in consideration of your comment regarding**

Organization	Yes or No	Question 2 Comment
dc grounds. References to dc grounds have been revised to "unintentional dc grounds." **5. We agree. The minimum activities have been revised in the standard to not require tripping of the breakers for this table entry.**		
Platte River Power Authority Maintenance Group	No	Minimum maintenance activities should be based on categorization of relays and defined maintenance actions system by system using historical and definitively known data entity by entity. By establishing specific minimum maintenance activities you risk entities changing currently effective maintenance programs to programs that match minimum maintenance activities to meet requirements in the standard which could be less effective for their system.
Response: The SDT thanks you for your comments. As for including some activities and excluding others, the listed activities are contemplated as minimum activities and do not preclude an entity from performing additional activities. Your use of historical and definitively known data may be applicable to a Performance-Based maintenance program (R3) for some of your activities.		
PacifiCorp	No	No comment.
Duke Energy	No	Our comments are limited to activities in Table 1a. 1. " Protective Relays " okay 2. " Voltage and Current Sensing Devices Inputs to Protective Relays " Proper functioning should be verified at commissioning, and then anytime thereafter if changes are made in a PT or CT circuit. Additional periodic checks may be warranted as suggested in Table 1A; however no additional checking should be required where circuit configuration will inherently detect problems with a PT or CT. For example, PTs & CTs that are monitored through EMS or microprocessor relays will be alarmed when they are out of specification. 3. "Protection System Control Circuitry (Breaker Trip Coil Only) (except for UFLS or UVLS) "Need more clarity on exactly what this activity is expected to include. In some cases we have a red light on a control panel monitoring the circuit path to the trip coil. In locations where there is not a red light, verifying the continuity of the breaker trip circuit including the trip coil will be complicated. There is no straightforward way to do it without potentially impacting reliability, and we would have to consider modifying these installations to include a red light. 4." Protection System Control Circuitry (Trip Circuits) (except for UFLS or UVLS) "Need more clarity on exactly what the activity is. We believe testing one output all the way to the coil is sufficient to prove the trip path. The activity states that "all auxiliary contacts" must be tested. We propose that all protection control circuitry should be tested at initial commissioning, and then again if any changes are made. Ongoing routine testing is complicated and could pose reliability challenges to the BES. As stated on page 8 of the System Maintenance Supplementary Reference document: "Excessive maintenance can actually decrease the

Organization	Yes or No	Question 2 Comment
		reliability of the component or system. It is not unusual to cause failure of a component by removing it from service and restoring it. The improper application of test signals may cause failure of a component. For example, in electromechanical over current relays, test currents have been known to destroy convolution springs. In addition, maintenance usually takes the component out of service, during which time it is not able to perform its function. Cutout switch failures, or failure to restore switch position, commonly lead to protection failures. 5.” Protection System Control Circuitry (Trip Circuits) (UFLS/UVLS Systems Only) Need additional clarity on exactly what the test includes. “Complete functional trip test” should not include tripping the breaker. Proving the output of the relay should be sufficient. Systems that have all load shed on distribution circuits should require that trip output be confirmed but should not be required through to the trip coil due to constraints in tying distribution load. 6. Station dc supply (that has as a component any type of battery) Under the 3 month interval activities, we disagree with the wording of the activity Verify that no dc supply grounds are present. The activity should instead read “Check for dc supply grounds and if any are found, initiate action to repair. 7. Station dc supply (that has as a component any type of battery) Under the 18 month interval activities, what is meant by “Verify continuity and cell integrity of the entire battery”? Also what is required to “Inspect the structural integrity of the battery rack”? The “Supplementary Reference Document” and “Frequently asked Questions” document should be made part of the standard to provide clarity to the requirements. 8. Station dc supply (that has as a component Valve Regulated Lead-Acid batteries) Need more clarity on exactly what is required for a “performance or service capacity test of the entire battery bank”. The “Supplementary Reference Document” and “Frequently asked Questions” document should be made part of the standard to provide clarity to the requirement. 9. Station dc supply (that has as a component Vented Lead-Acid batteries) Need more clarity on exactly what is required for a “performance, service, or modified performance capacity test of the entire battery bank”. The “Supplementary Reference Document” and “Frequently asked Questions” document should be made part of the standard to provide clarity to the requirement. 10.” Protection system communication equipment and channels Need additional clarity on exactly what is required for the substation inspection. What is required for power-line carrier systems? 11. UVLS and UFLS relays that comprise a protection scheme distributed over the power system Need more clarity regarding the meaning of “distributed over the power system”.
Response: The SDT thanks you for your comments.		

Organization	Yes or No	Question 2 Comment
1. Thank you. **2. Your example describes attributes applicable to Table 1c, and which would not require periodic maintenance. If monitoring, as you've described, is not present, periodic verification is necessary as described in Table 1a.** **3. You are correct. This area of each of the Tables has been extensively revised in response to comments. FAQ II-4-C (page 10) explains that this "may be via targeted maintenance activities or by documented operation of these devices for other purposes such as fault clearing" and Section 15.3 of the Supplementary Reference (page 22) provides discussion on this.** **4. If only one path is tested, this provides no assurance that other paths will perform properly. The cited reference on Page 8 of the Supplementary Reference Document is focused on effective maintenance intervals, not on performing maintenances. There are methods of performing functional testing without injecting damaging test currents.** **5. The requirement has been modified to provide more clarity, and has been modified to remove the requirement to actually trip the breaker.** **6. The SDT has modified the standard in consideration of your comment – it now reads, "Check for unintentional grounds."** **7. The SDT has modified the standard in consideration of your comment on cell integrity of the entire battery. Also, the Protection System Maintenance Frequently Asked Questions document (FAQ II-5-H, page 15) that accompanied the standard for this comment period addresses your question about the battery rack in Station dc Supply section. According to the NERC Standard Development Procedure, a standard is to contain only the prescriptive requirements; supporting discussion is to be in a separate document.** **8. Methodologies regarding performance and service capacity tests for VLRA batteries are explained in detail in various available references. According to the NERC Standard Development Procedure, a standard is to contain only the prescriptive requirements; supporting discussion is to be in a separate document.** **9. Your comment is in the nature of a "how to", not a requirement, and therefore the SDT believes it belongs in the supporting discussion. According to the NERC Standard Development Procedure, a standard is to contain only the prescriptive requirements; supporting discussion is to be in a separate document.** **10. FAQ II-6-A (page 16) presents a variety of methods to maintain Protection System communication equipment.** **11. This refers to the common practice of applying UFLS on the distribution system, with each UFLS individually tripping a relatively low value of load. Therefore, the program is implemented via a large number of relays, and the failure of any individual relay to perform properly will have a minimal effect on the effectiveness of the UFLS program. There are some UVLS systems that are applied similarly.**		
Progress Energy	No	Progress Energy does not agree with the activity "Verify that the battery charger can perform as designed by testing that the charger will provide full rated current and will properly current-limit." We are unclear how this test should be performed.
Response: The SDT thanks you for your comments. The SDT has modified the standard in consideration of your comment. The component description was changed to: Station dc supply (which do not use a station battery) And the maintenance activity was changed to: Verify that the dc		

Organization	Yes or No	Question 2 Comment
supply can perform as designed when the ac power from the grid is not present.		
Xcel Energy	No	Regarding battery chargers, does the SDT propose that OEM-type tests be performed to validate the rated full current output and current limiting capabilities? It has been proposed that simply turning off the charger and allowing the batteries to drain for a period of several hours, then returning the charger to service will validate these items. It is not clear that an auditor would come to the same conclusion, since it appears open to interpretation. Please modify to make this clear. If an entity has an over-sized battery charger, they can (and should) only test to the max capacity of the battery bank. Suggest changing “full rated current” to “designed charging rate”.
Response: The SDT thanks you for your comments. The SDT has modified the standard in consideration of your comment. The component description was changed to: Station dc supply (which do not use a station battery) **And the maintenance activity was changed to:** Verify that the dc supply can perform as designed when the ac power from the grid is not present.		
Austin Energy	No	See item # 10 Comments
Response: See #10 Response		
Otter Tail Power	No	Station DC supply - (Maintenance Activity) As a company we do not think that measuring specific gravity and temperature of each cell is necessary. There is a better test that we use with the Bite Impedance Test. We have had good success with the impedance test for determining the batteries condition. See article (Impedance Testing Is The Coming Thing For Substation Battery Maintenance)written in Transmission & Distribution 11/1991 by Richard Kelleher, Test & Maintenance Specialist, Northeast Utilities.
Response: The SDT thanks you for your comments regarding DC supply. Changes have been made to the standard in consideration of your comments. The requirement to measure specific gravity and temperature of each cell has been deleted.		
Detroit Edison	No	1. Suggest that under “Maintenance Activities” for “Protective Relays” add the following: Verify proper functioning of the microprocessor relay external logic inputs (carrier block, etc.) 2. We recommend not requiring specific gravity and temperature readings for batteries. We have found from experience that the time and difficulty to obtain specific gravity readings are not justified. We have found that utilizing visual inspections, voltage and internal/intercell resistance readings gives a good picture of the health of the battery. We use specific gravity readings on occasion for troubleshooting purposes. 3. It is recommended that the sections about verifying battery charger performance be eliminated if there are low voltage alarms that go to a monitored location.

Organization	Yes or No	Question 2 Comment
		4. We recommend changing the maximum maintenance interval for DC supplies with no battery from 18 months to 3 years. If there is no battery, you do not have the risk of failure of chemical processes and such that would require an interval as short as 18 months.
Response: Thank you for your comments 1. **The SDT has modified the standard in consideration of your comment. The revised activity reads as follows:** For microprocessor relays, check the relay inputs and outputs that are essential to proper functioning of the Protection System **2. Thank you for your comments regarding DC supply. The SDT has modified the standard in consideration of your comment. The requirement to measure specific gravity and temperature of each cell has been deleted.** **3. Changes have been made to the standard in consideration of your comments regarding verifying battery charger performance. The only requirement relative to battery chargers in the latest draft of the standard (see Table 1a, pg 14) is to verify the float voltage.** **4. The SDT disagrees; the 18-month interval includes several items that can be verified only by physical inspection; that are independent of chemical processes, and that affect the ability of the dc supply to perform properly.**		
SCE&G	No	1. Table 1a Level 1 Monitoring has a requirement to “Verify the continuity of the breaker trip circuit including trip coil” at least every 3 months. This is interpreted to be applicable to both the low-side generator output breaker and the high-side breaker for the GSU. The generator output breaker has 3 separate trip coils (one for each pole) that are connected in a parallel configuration and there is no means available to verify continuity of each of these coils INDIVIDUALLY in this arrangement. Is the intent of this requirement to have each trip signal parallel leg verified every three months even though the trip contacts are normally open (these circuits are functionally checked during LOR Functional Verification)? 2. Also, is the Red Indication Light (RIL), which includes the trip coil in the power circuit, adequate for verification (note that the breaker does not include the parallel legs that contain the tripping sensor contacts)? 3. Also, more clarification is needed on the section “Verify proper functioning of the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays” under “Voltage and Current Sensing Devices Inputs to Protective Relays.” How would this be done if no redundancy is available for cross-checking voltage and current sources? 4. In certain situations, “verify proper functioning” is not clear enough. Documentation of verification consistent with the entities procedures should be adequate to indicate compliance.
Response: The SDT thanks you for your comments. **1. The SDT has modified the standard to remove the requirement cited in your comment.**		

Organization	Yes or No	Question 2 Comment
2. The SDT has modified the standard to remove the requirement cited in your comment. **3. The Supplementary Reference Document, Section 15.2 (page 21) and FAQ II-3 (page 8) provides several discussions on this item.** **4. Documentation of verification consistent with your procedures is sufficient to "verify proper functioning"**		
Dynegy	No	Table 1a requires entities to "verify the continuity of the breaker trip circuit including trip coil..." The term "verify" needs clarification. For example, we believe verifying red and green" lights during routine inspection should be sufficient. On the other hand, actual testing is not feasible and is risky to reliability.
Response: The SDT thanks you for your comment, and has modified the standard to remove the requirement cited in your comment.		
Nebraska Public Power District	No	1. Table 1a, for Protective Relays identifies the following Maintenance Activities: Test and calibrate the relays (other than microprocessor relays) with simulated electrical inputs. Verify proper functioning of the relay trip outputs. What is the difference between these two requirements? They appear to be practically equivalent. 2. Tables 1a & 1b, for Station DC supply identify the following Maintenance Activity: Measure that specific gravity and temperature of each cell is within tolerance (where applicable). What is the advantage of testing the SG in every cell compared to using a pilot cell as representative sample of the entire bank? NPPD has not experienced any problems using a pilot cell compared to testing every individual cell. Typically, if the SG is low the cell voltage will be low, which is detected by the voltage test. This seems to be an excessive requirement and does increase personnel exposure to hazardous fluid. What unique information is provided by this test that other tests do not provide?
Response: The SDT thanks you for your comments. **1. The SDT has modified the standard in consideration of your comment. The activity to "verify proper functioning of the relay trip outputs was changed to:** Verify that settings are as specified. **2. The SDT thanks you for your comments regarding DC supply and has made changes to the standard in consideration of your comments. The requirement to measure specific gravity and temperature of each cell has been deleted.**		
ENOSERV	No	1. Table 1A, protective relays for 6 calendar years, Testing and calibrating the relays other than microprocessors relays with simulated electrical inputs... does that mean that micro processor relays do not need to be checked? 2. Verify proper function of the relay trip outputs... Does this involve both electro AND micro processors? Then when mentioning the verifying microprocessor relays, does that include the trip output.

Organization	Yes or No	Question 2 Comment
Response: The SDT thanks you for your comments. **1. Yes. The SDT has modified the standard for clarity. The maintenance activities for microprocessor relays were changed to read as follows:** For microprocessor relays, check the relay inputs and outputs that are essential to proper functioning of the Protection System. For microprocessor relays, verify acceptable measurement of power system input values. **2. Yes. The SDT has modified the standard for clarity. The language for microprocessor relays was changed as noted in response to your first comment; the following modification addresses all protective relays:** Verify that settings are as specified.		
Southern Company	No	1. Tables 1a and 1b require entities to verify the proper operation of voltage and current inputs to sensing devices on a 12 year interval. The Protection System Supplementary Reference (Draft 1), in section 15.2, describes several methods that may be used for such verification efforts. In order to perform this type of verification the circuit in question would need to be in operation. This verification introduces a possible unit trip due to the need to connect test equipment to live potential and current circuits at each relay, which has the potential to trip the circuit under test. This could result in the loss of critical transmission lines or generating units. The System Maintenance Supplementary Reference also allows saturation tests or circuit commissioning tests to satisfy this requirement; however, these types of tests require the circuit in question to be removed from service. For generating plants, removing the circuit from service requires that the station be shut down. We do not feel that the value obtained from this requirement is equal to the risk or maintenance burden associated with it. Such testing and verification should not be required periodically, but only if new instrument transformers, cabling or protective devices are installed or if the instrument transformers are replaced. 2. Table 1b: Protection System Control Circuitry (Trip Coils and Auxiliary Relays) “ Experience has shown that electrically operating partially monitored breaker trip coils, auxiliary relays, and lockout relays every 6 years is not warranted. This testing introduces risk from a human error perspective as well as from additional switching and clearances required. We recommend eliminating this maintenance requirement. 3. Protection System Control Circuitry (Trip Circuits) (UFLS or UVLS Systems Only) - Table 1b includes the statement "Verification does not require actual tripping of circuit breakers or interrupting devices." This statement should be included in Table 1a. 4. In Table 1a “Station DC Supply (that has as a component any type of battery), we recommend changing the maximum maintenance interval from 3 months to 6 months as described below. 5. “Verify Proper Electrolyte Level “3 Months - The 3 months interval for verifying proper electrolyte level is excessive for current battery designs that are properly maintained. The interval in which the electrolyte must be replenished is affected by many factors. These include temperature, float voltage, grid material, age of the

Organization	Yes or No	Question 2 Comment
		battery, flame arrester design, frequency of equalization, and electrolyte volume in the battery jar. Manufacturers are aware that their customers want to extend the interval in which their batteries require water and this has lead to jar designs that have a wide min-max band with a high volume of electrolyte to allow for extended watering intervals. Understanding all the factors and proper maintenance will extend watering intervals. A battery should go a year or more between watering intervals and some as many as 3 years. Being conservative the Southern Company Substation Maintenance Standards require that we check the electrolyte level twice yearly. Experience has shown this has worked well. We propose that the “3 Months” interval be changed to “6 months”. 6.”Verify proper voltage of the station battery “3 Months - Being conservative, the Southern Company Substation Maintenance Standards require that we check the station battery voltage twice yearly. Experience has shown this has worked well. We propose that the “3 Months” interval be changed to “6 months”. 7.” Verify that no dc supply grounds are present “3 Months Being conservative, the Southern Company Substation Maintenance Standards require that we check for dc supply grounds twice yearly. Experience has shown this has worked well. We propose that the “3 Months” interval be changed to “6 months”. 8. Measurement of Specific Gravity 18 Months- The measurement of specific gravity and temperature every 18 months is not necessary as a regular part of maintenance. Specific gravity can provide information as to the health of a cell; however, taking specific gravity readings is a messy process no matter how careful you are and will result in acid being dripped on top of the battery jars as the hydrometer is moved from cell to cell. Should a drop of acid end up on an external connection, it will result in corrosion and problems later. Voltage reading of cells can be substituted for specific gravity readings under normal conditions. Specific gravity is equal to the cell voltage minus 0.85. A cell with low voltage will have a low specific gravity. If cell voltage becomes a problem that cannot be addressed through equalization then specific gravity readings are justified as a follow-up test. Since measurement of specific gravity could lead to problems and reading cell voltage is a viable alternative, we propose that it be removed from the battery maintenance activities. 9. Verify Cell to Cell and Terminal Connection Resistance 18 Months - Clarification is needed on the expected method for verifying cell to cell and terminal connection resistance. This could easily be interpreted as requiring the use of an ohmic value (impedance/conductive/resistance) test device. If this is the case then basically it eliminates the need for the activity to “Verify that the substation battery can perform as designed by performing a capacity test every 6-Calendar Years or performing an ohmic value test every 18 Months”, because the practical thing to do is go ahead and perform the ohmic value test while you have your device connected to the battery. 10. In table 1a and 1 b - Station dc supply (that has as a component -Vented Lead-Acid batteries). Verify that the Substation Battery can Perform as Designed 6 Calendar Years/18 Months - Southern Company Transmission has approximately 570 batteries that are covered by this proposed standard. These batteries currently have ohmic value testing performed every “4 Years” as required by the Southern Company

Organization	Yes or No	Question 2 Comment
		Substation Maintenance Standards. The “4 Years” interval has been utilized for over 10 years and has not experienced a failure of any of the 570 batteries to perform as designed Having to perform ohmic value testing on an “18 Months” interval will significantly increase our costs and manpower requirements with no anticipated improvement in reliability. We propose that the “18 Months” interval for ohmic value testing be changed to “4 Calendar Years”. This proposal also applies to verifying cell to cell and terminal connection resistance if an ohmic value test device is required as discussed above. 11. In table 1a and 1b Station dc supply (that uses a battery and charger). Verify that the Battery Charger can Perform as Designed 6 Calendar Years - Clarification is needed on an acceptable method for verifying that the battery charger can perform as designed by testing that the charger will provide full rated current and will properly current limit, especially the part about “will properly current limit”. 12. On Table 1b Station DC Supply (that has a component any type of battery) we recommend changing the maximum maintenance interval from 3 months to 6 months as described below “ Verify Proper Electrolyte Level “ 3 Months - The 3 months interval for verifying proper electrolyte level is excessive for current battery designs that are properly maintained. The interval in which the electrolyte must be replenished is affected by many factors. These include temperature, float voltage, grid material, age of the battery, flame arrester design, frequency of equalization, and electrolyte volume in the battery jar. Manufacturers are aware that their customers want to extend the interval in which their batteries require water and this has lead to jar designs that have a wide min-max band with a high volume of electrolyte to allow for extended watering intervals. Understanding all the factors and proper maintenance will extend watering intervals. A battery should go a year or more between watering intervals and some as many as 3 years. Being conservative the Southern Company Substation Maintenance Standards require that we check the electrolyte level twice yearly. Experience has shown this has worked well. We propose that the “3 Months” interval be changed to “6 months”. 13. We recommend removing the “Detection and alarming of dc grounds” monitoring attribute. Note that this applies to every “Station dc supply” section where it is listed. .Experience has shown that there have been no significant problems discovered via alarms that would not have been discovered by 6 month inspection cycles. We propose to add “verify no dc grounds are present” as a maintenance activity on a 6 months inspection cycle. Experience has shown that there have been no significant problems discovered via alarms that would not have been discovered by 6 month inspection cycles. 14. Table 1a, p. 7, Station dc supply, 3 month interval: need to add “unintentional” to the sentence “Verify that no dc supply grounds are present.” Because most dc systems have ground detection systems which place an intentional ground on the battery. “No grounds” is not practical and is unacceptable since most dc systems have some high resistance ground paths. Some criteria should be established to determine the acceptable ground resistance on a dc system. 15. Table 1a, p. 8: For the vented, lead-acid battery, there is no basis for the 18 month activity option

Organization	Yes or No	Question 2 Comment
		(internal ohmic value measurement) in place of the 6 year performance test. 16. The activities for trip checks for Level 1A and Level 1B should be the same. Currently, they read: Level 1a: Perform a complete functional trip test that includes all sections of the Protection System trip circuit, including all auxiliary contacts essential to proper functioning of the Protection System. Level 1b: Verify that each breaker trip coil, each auxiliary relay, and each lockout relay is electrically operated within this time interval. The Level 1a text is adequate for 1b also. 17. Table 1c, p 16: Monitoring of single or parallel trip circuits is not practical where multiple normally open contacts are in series to trip. Monitoring of the trip coils is practical and useful. How would one monitor several normally open contacts which are in series to trip a breaker? 18. Table 1c, p. 15, 16, 19: The use of “continuous” under “Maximum Maintenance Interval” in Table 1c should be changed to “N/A” and the Maintenance Activity should be “NONE”. 19. Verification of the various monitoring (automated notification) systems is not specified anywhere in the requirements. This, too, should be required.

Response: The SDT thanks you for your comments.

1. The SDT believes that proper functioning of the sensing devices is a vital component of the Protection System performance, and that they must be maintained as specified in the Standard. To minimize system impact of such maintenance and possible errors, the maintenance necessarily should be scheduled at a time that minimizes the risks.

2. The SDT believes that proper functioning of the Protection System Control Circuitry is a vital component of the Protection System performance and those must be maintained as specified in the standard. To minimize system impact of such maintenance and possible errors, the maintenance necessarily should be scheduled at a time that minimizes the risks

3. The SDT has modified the standard in consideration of your comment. The following was added to Table 1a:

> **Type of Component -** Control and trip circuits with electromechanical trip or auxiliary (UFLS/UVLS Systems Only)
>
> **Maximum Maintenance Interval -** 6 Calendar Years
>
> **Maintenance Activity -** Perform a complete functional trip test that includes all sections of the Protection System control and trip circuits, including all electromechanical trip and auxiliary contacts essential to proper functioning of the Protection System, except .that verification does not require actual tripping of circuit breakers or interrupting devices.

4. Please see responses 5, 6 and 7 (below) for discussion regarding your concern about extending the Maximum Maintenance Intervals for an extra 3 months on activities related the station dc supply.

5. The SDT agrees that a healthy modern lead acid battery can go for extended periods of time beyond 3 months without requiring watering. However, checking cell electrolyte level not only indicates the need for battery watering, it is an indication of an individual cell’s health and needs to remain at

Organization	Yes or No	Question 2 Comment
the Maximum Maintenance Interval of 3 months. To avoid the confusion that the Maintenance Activity listed in Table 1 was to water the battery at the specified 3 month interval, the Drafting Team has changed the wording of the Maintenance Activity from “verify proper” to “check” electrolyte level. 6. Thank you for your comment to extend the Maximum Maintenance Interval for checking the station dc supply voltage. The SDT believes that extending the Maximum Maintenance Interval beyond that listed in Table 1 would compromise the performance of the station dc supply. 7. Due to the consequences of unintentional grounds to the station dc control system, the SDT feels that extension of the Maintenance Intervals beyond the 3 month interval is not prudent. See FAQ IV-2-F (Page 23). 8. Changes have been made to the standard in consideration of your comments regarding specific gravity testing, and the revised standard does not include a requirement to perform this maintenance activity. 9. Thank you for your comments concerning performance of ohmic measurement at the same time that connection resistance is measured. As you suggested, these two measurements could be taken at the same time to meet the requirements of their respective Maintenance Activities. 10. Thank you for your comments concerning evaluating internal ohmic values and measurement of battery connection resistance for Vented Lead-Acid (VLA) batteries. As noted in your comment an owner has two different Maintenance Activities with associated different Maximum Maintenance Intervals to choose from in verifying that the VLA station battery can perform as designed. FAQ II-5-F (page 14) and II-5-G (page 14) provides an explanation of why there are two different intervals for these Maintenance Activities is given. Because trending is an important element of ohmic measurement evaluation, the SDT believes that extending the Maximum Maintenance Interval listed in Table 1 for evaluating internal ohmic values to four years as suggested would not provide the necessary information for proper evaluation of the ability of the station battery to perform as designed. Concerning verifying cell to cell and terminal connection resistance as part of inspecting the battery, various technical references on Lead-Acid battery maintenance talk about how and why this Maintenance Activity should be performed at the Maximum Maintenance Interval listed in Table 1. The SDT believes that to extend this inspection activity for the connections of a Lead-Acid battery beyond the Maximum Maintenance Interval would compromise the performance of the station dc supply. 11. The SDT has modified the standard in consideration of your comment regarding battery charger performance. The only remaining maintenance activity relevant to the battery charger is to verify the float voltage. 12. The SDT agrees that a healthy modern lead acid battery can go for extended periods of time beyond 3 months without requiring watering. However, checking cell electrolyte level not only indicates the need for battery watering, it is an indication of an individual cell’s health and needs to remain at the Maximum Maintenance Interval of 3 months. To avoid the confusion that the Maintenance Activity listed in table 1 was to water the battery at the specified 3 month interval, the Drafting Team has changed the wording of the Maintenance Activity from “verify proper” to “check” electrolyte level. 13. Thank you for your comments concerning the monitoring attribute for unintentional dc grounds on the station dc supply. Due to the consequences of unintentional grounds to the station dc control system (see FAQ II-5-I, page 15), the SDT feels that monitoring for them is an important part of an effective condition based maintenance program and should be an option available for those who want to perform condition based maintenance. Also because the threat to the dc system and the BES that unintentional dc grounds create, the SDT feels that extension of the Maintenance Intervals for		

Organization	Yes or No	Question 2 Comment
checking for unintentional dc grounds beyond the 3 month interval is not prudent. See FAQ IV-2-F (page 23). **14. The SDT has modified the standard in consideration of your comment regarding dc grounds – the word, "unintentional" was added as proposed.** **15. The SDT thanks you for your comment concerning ohmic value measurements. The FAQ II-5-F (page14) includes an explanation for the basis of this activity. The SDT believes that this Maintenance Activity is a viable alternative that a Vented Lead-Acid battery owner can perform at the Maximum Maintenance Interval of Table 1 in place of conducting a performance, modified performance or service capacity test.** **16. For Table 1b, much of the DC control circuit is, by definition, being monitored; therefore, the only requirement is that the electromechanical devices be exercised.** **17. With the detail provided in your comment, it appears to the SDT that you would not be able to use Table 1c in this example.** **18. "Continuous" is intended to clarify that the maintenance is being performed continuously via the monitoring system and the Activities portion of the table is intended to state those activities that are being performed by the monitoring system.** **19. This verification is established within the "General Description" at the top of Table 1c as generic criteria to use this table.**		
Transmission Owner	No	a. Tables 1a, 1b & 1c should offer as an alternative, measuring battery float voltages and float currents in lieu of measuring specific gravities as described in Annex A4 of IEEE Std 450-2002. b. Inspection of CVT gaps, MOVs and gas tubes should be added to the communications equipment time based maintenance tables. Failure of the CVT protective devices may cause failure of the Protection System. c. Maintenance Activities for UVLS or UFLS station dc supplies shows "Verify proper voltage of dc supply". Does this imply that, except for voltage readings of the dc supply, distribution battery banks are not maintained? d. Why does the Maintenance Activities for UVLS or UFLS relays state that verification does not require actual tripping of circuit breakers? e. Please clarify the Maintenance Activities for Voltage and Current Sensing Devices. Must voltage, current and their respective phase angles be measured at each discrete electromechanical relay?
Response: The SDT thanks you for your comments. **a. The SDT has modified the standard in consideration of your comment regarding dc supply. All references to measuring specific gravities have been removed from the revised standard – and for Table 1a for station dc supply, the language was revised to require, "Verify float voltage of battery charger."** **b. Power line carrier channels are made up of many components that must be maintained on a periodic basis. This standard indicates that adequate maintenance and testing must be done to keep the performance of the channel at a level that meets the requirements of the relay system. The**		

Organization	Yes or No	Question 2 Comment
determination of specific maintenance activities is the responsibility of the Entity. c. This standard limits the maintenance requirements of distribution system batteries to those used for UVLS and UFLS and constrains those requirements to verification of proper voltage. If "distribution system" batteries are used for any other BES Protection System applications, they must be maintained according to the other requirements of this standard. d. The SDT believes that the UFLS scheme is predominantly based within the distribution sector. As such, there are many circuit interrupting devices that will be operating for any given under-frequency event that requires tripping for that event. A failure in the tripping-action of a single distribution breaker will be far less significant than, for example, any single Transmission Protection System failure such as a failure of a Bus Differential Lock-Out Relay. While many failures of these distribution breakers could add up to be significant, it is also believed that distribution breakers are operated often on just fault clearing duty and therefore the distribution circuit breakers are operated at least as frequently as any requirements that might have appeared in the standard. e. Not exactly. The requirement is that the entity must verify that proper voltage, current, and phase angle is delivered to the relays. The standard does not prescribe methodology. See FAQ II-3-A (page 8) and the Supplementary Reference Document, Section 15.2 (page 21) for a discussion on this topic.		
Pepco Holdings Inc.	No	1. Tables 1a, 1b and 1c all require measuring specific gravity and temperature of battery cells. This invasive test provides no information regarding battery health that cannot be obtained from cell impedance testing. Recommend requiring cell impedance OR specific gravity & cell temperature testing. 2. Tables 1a, 1b and 1c all require testing the battery charger every 6 years to verify that it can provide full rated current and will properly current limit. In order to perform this (unnecessary) test the battery would be subjected to a deep discharge. Whatever benefits may be derived from this test are dwarfed by the negative effect on the battery. Recommend removing this requirement.
Response: The SDT thanks you for your comments. 1. The SDT has made changes in consideration of your comments regarding measuring of specific gravity and temperature of battery cells and removed this maintenance activity from the revised standard. 2. The SDT has modified the standard in consideration of your comments regarding battery charger performance. All maintenance activities relating to the battery charger were removed except for verification of the float voltage.		
Illinois Municipal Electric Agency	No	1. The Illinois Municipal Electric Agency (IMEA) is concerned the minimum maintenance activities may be too prescriptive for transmission subsystems that essentially operate radially. 2. Please see comment under Question 7. 3. Also, IMEA supports comments submitted by Florida Municipal Power Agency regarding applicability to

Organization	Yes or No	Question 2 Comment
		UFLS systems.
Response: The SDT thanks you for your comments. **1. This standard applies Protection Systems that that are applied on, or are designed to provide protection for the BES. The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. The SDT has therefore defined the minimum activities necessary to implement an effective PSMP.** **2. Please see our response to your comments under Question 7.** **3. The SDT has responded to the FMPA comments regarding UFLS systems.**		
Consumers Energy Company	No	1. The second sentence in Note 1 on page 20 should be changed to “A calibration failure is when the relay is inoperable and cannot be brought within acceptable parameters.” 2. Note 2 should be changed to “Microprocessor relays typically are specified by manufacturers as not requiring calibration. The integrity of the digital inputs and outputs will be verified by applying the inputs and verifying proper response of the relay. The A/D converter must be verified by inputting test values and determining if the relay measurements are correct.”
Response: The SDT thanks you for your comments. **1. The standard establishes a calibration failure to be any condition where the relay is found to be out of tolerance, whether or not it can be restored to acceptable parameters. The condition described is a calibration failure that is also a “maintenance correctable issue” as established in revisions to R4 and the resulting footnote, and requires more extensive action to resolve.** **2. Note 2 has been removed and the relevant requirements added to the Tables themselves. There are methods, other than inputting test values, to verify the A/D converter.**		
American Transmission Company	No	1. The Standard should focus on identifying the types of components to be tested but should not identify the specific maintenance activities that must be performed. Entities should be allowed the flexibility to develop and implement the appropriate maintenance activities necessary for each identified component. 2. ATC is also concerned with the expressed identification of maintenance intervals. We do not believe that the standard should identify specific maintenance intervals but that it should require entities to identify their maintenance intervals appropriate for their system. If the team continues to pursue specific maintenance intervals it will be establishing the industries practices. 3. Specific Concern: The standard identifies that entities should perform complete functional testing as part of its maintenance activities, but we are concerned that this could lead to reduced levels of reliability, because it

Organization	Yes or No	Question 2 Comment
		requires entities to remove elements from service and then requires entities to perform tests that are inherently prone to human errors. We believe that the perceived benefits do not match the anticipated costs or improve system reliability.
Response: The SDT thanks you for your comments. As you are probably aware, protection systems have contributed to most major events, indicating a need to provide greater "defense in depth" to the body of standards. While many facility owners do have effective protective system maintenance programs, some do not – which puts the grid at risk. **1. Specific activities are defined where necessary to implement an effective PSMP, and has provided for flexibility where there are multiple methods that will be effective.** **2. FERC Order 693 expressly directs NERC to develop maximum maintenance intervals.** **3. The SDT believes that complete functional testing is a vital component of the Protection System performance, and must be performed as specified in the standard. To minimize system impact of such maintenance and possible errors, the maintenance necessarily should be scheduled at a time that minimizes the risks.**		
Wolverine Power Supply Cooperative, Inc.	No	The tables are too prescriptive - The standards should state what, not how.
Response: The SDT thanks you for your comments. The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. The SDT has therefore defined the minimum activities necessary to implement an effective PSMP.		
Northeast Power Coordinating Council	No	1. We agree there is a need for minimum maintenance activities; however, the standard does not clearly define the differences between Table 1a, 1b, and 1c. It is recommended that the drafting team develop definitions for the equipment listed in these tables. For example, Table 1a equipment consists of mechanical and solid state equipment without monitoring capability, Table 1b consists of mechanical and solid state equipment with monitoring capability, and Table 1c consists of equipment capable of self monitoring. 2. In addition, all battery, charger and power supply maintenance activities should be removed from Table 1a, 1b, and 1c, and summarized in a separate Table (i.e. Table 2). Tables 1a and 1b for 'Station dc supply (that has as a component any type of battery) and Table 1c for 'Station dc Supply (any battery technology) for an 18 Month 'Maximum Maintenance Interval' identifies the need to 'Measure that the specific gravity and temperature of each cell is within tolerance (where applicable).' 3. Following industry best practices, we would recommend using the MBRITE diagnostic test. MBRITE testing provides more information than a specific gravity test while reducing the risk of injury to testing

Organization	Yes or No	Question 2 Comment
		personnel. 4. In Table 1a, the Type of Component "Protection system communications equipment and channels." has a 3 month "Maximum Maintenance Interval". Clarification needs to be provided as to how an unmonitored (do not have self-monitoring alarms) will be tested. 5. Table 1a refers to "Unmonitored Protection Systems". The "6 Calendar Years" "Maximum Maintenance Interval" "Maintenance Activities" is excessive.
Response: The SDT thanks you for your comments. **1. The component differences between Table 1a, Table 1b, and Table 1c are described in the header to the Tables and in the specific monitoring attributes for the specific component types. Please see the decision trees near the end of the FAQ document (pages 33-37).** **2. The SDT believes that the Station DC Supply component should be addressed with the other components, and has simplified the Tables in consideration of your comments.** **3. The DC Supply component has been modified, and no longer specifically requires specific gravity testing.** **4. See FAQ II-6-B (page 16) for a discussion of a number of methods to test the communications systems.** **5. Your comment is unclear, and the SDT is unsure how to respond. The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. The SDT has therefore defined the minimum activities and maximum intervals necessary to implement an effective PSMP. Some entities may feel that they need to maintain Protection System components more frequently.**		
Lower Colorado River Authority	No	We agree with all stated intervals except for the maximum stated interval of 6 years for Protection System Control Circuitry (Trip Coils and Auxiliary Relays) in tables 1b and 1c. What was the intent of separating this interval out from the Protection System Control Circuitry (Trip Circuits), which is 12 years for monitored components? Monitoring of the trip coils should be enough to justify a maximum interval of 12 years. As stated these requirements will put an undue financial and resource burden on utilities that have updated their protective relay systems with state-of "the art components and monitoring. In addition to the expense and effort of scheduling the additional maintenance, the additional validation of lockouts and auxiliary relays, separate from the full function testing could lead to additional human errors and accidental tripping of circuits while testing. We believe there should be one stated activity "Protection System Control Circuitry and have a maximum interval of 12 years for monitored systems.
Response: The SDT thanks you for your comments. **Monitoring of the coil of these devices does not assure that the device will mechanically operate properly. Electromechanical devices such as lockout**		

Organization	Yes or No	Question 2 Comment
relays and auxiliary relays must be exercised periodically to assure proper operation. The monitoring systems cannot perform this. See Supplementary Reference Document Section 15.3 (page 22).		
Ameren	No	We agree with the vast majority of them, listed below are our few concerns, questions, and pleas for clarification. 1) We disagree with doing specific gravity and temperature of every cell in the 18 month test because the other tests being done are already comprehensive. 2) FAQ 3B p 29 digital relay A/D verification should include simply comparing digital relay displayed metered values to another metered source. 3) FAQ 3A p6 Change “prove that” to “verify”. For single CT or VT, this can be challenging and some measure of reasonableness in determining an expected value comparable to the measured value must be acceptable. 4) FAQ 1B p17 Combining evidence forms of “Process documentation or plans” and “Data” or “screen shots” shows compliance. Please add an example or verbiage to clarify that a field technician’s (or operator) recorded check-off combined with a company’s process is sufficient evidence. Otherwise documentation alone could consume considerable field personnel time. 5) FAQ p2 Add FAQ to clarify “verify settings”. If EM relays are included, explain that minor tap or time dial differences of the order of relay tolerances are acceptable. For digital relays state that software compare functions are a sufficient means to “verify settings.” 6) Omit Table 1b row 3 because row 4 actually applies to Monitoring Level 2 Trip Circuits. Row 3 already appears in Table 1a, and repeating it in Table 1b is confusing. 7) FAQ 4D p 7 then defines auxiliary relays as device 86 and 94. Does device number nomenclature or function determine and restrict inclusion? 8) Please state that “a location where action can be taken for alarmed failures” would include a dispatch center or control room. From there the custodial authority would be called out to take action. 9) Please explain the expansion from station battery to station DC supply, specifically the addition of the charger, an AC to DC device. 10. The charger load test up to its current limiter would add a significant amount of work with little known benefit. 11. Have charger problems been a significant cause of cascading outages? 12) We oppose your expansion of Station DC Supply to UFLS (the last row on page 8.) PRC-008-0 is

Organization	Yes or No	Question 2 Comment
		restricted to UFLS equipment. UFLS is often applied in distribution substations to trip feeders directly serving load. Your scope expansion has the potential to greatly increase the number of substation DC Supplies covered by NERC standards. ,. While we agree that UFLS is BES applicable, and those substations are included in our overall maintenance program, this expansion to NERC scrutiny is not warranted. Have there been UF events in which a material amount of load was not shed because of DC problems? UFLS is spread out amongst many distribution stations, and even if a couple did fail to trip in an underfrequency event, it would have little effect. 13) FAQ 2 p 17 expands the scope at Generating Facilities so that system connected station auxiliary transformers would be included. We oppose this expansion as these are radially served loads, and they often do not result in generation loss. Even if they did, the BES can readily tolerate the loss of a single generator.

Response: The SDT thanks you for your comments.

1. **All references to specific gravity and temperature testing have been removed from the revised standard.**
2. **The FAQ has been revised and reorganized in response to many industry comments; see FAQ II-3 (all subsections – pages 8-10) for a discussion of this topic.**
3. **The FAQ has been revised and reorganized in response to many industry comments; see FAQ II-3 (all subsections – pages 8-10) for a discussion of this topic.**
4. **The FAQ has been revised and reorganized in response to many industry comments; see FAQ IV-1-B (page 21)**
5. **See FAQ II-2-D & II-2-E(pages 6-7).**
6. **Table 1a and Table 1b each stand alone; use the table that is relevant to the level of monitoring that is implemented.**
7. **The SDT modified the FAQ to remove references to the IEEE device numbers (page 11) except when essential to respond to the question. Regardless of how the device is described by internal entity nomenclature, the function of the device determines whether it is included within the standard.**
8. **Your suggestion is properly considered as an example. See FAQ V-1-A (page 28).**
9. **The SDT believes that the charger is an integral portion of the Station DC supply; thus it has been added. The SDT has modified the standard to simplify the requirements related to maintenance of the battery charger.**
10. **The SDT modified the standard in consideration of your comment. All maintenance activities pertaining to battery chargers have been removed except verification of the float voltage.**
11. **The standard addresses overall Protection System reliability, not only those issues that may cause cascading outages.**
12. **The SDT believes that verification of the DC supply voltage to the UFLS is not burdensome. The SDT has modified the standard to clarify that the**

Organization	Yes or No	Question 2 Comment
only DC Supply requirement relevant to UFLS is to verify the DC supply voltage. **13. Station service transformers are essential to starting the plant during grid recovery. The FAQ clarifies why these elements are included. The standard addresses overall Protection System reliability, not only those issues that may cause extreme outages.**		
Manitoba Hydro	No	1. What documentation or evidence is required to prove that the Protection System Control Circuitry has been maintained every three months, if just a visual inspection of the breaker control trip circuit RED panel light has been completed, to verify continuity of breaker trip coil? 2. How do we handle breakers with dual trip coils and only one RED light for trip coil continuity? 3. What do the terms DISTRIBUTED and CENTRALIZED with respect to UFLS mean? 4. In Table 1C under the heading "Maximum Maintenance Interval" some of the entries are stated as being "Continuous". In the case of other maintenance activities the descriptor for Maintenance Interval indentifies the maximum period of time that may elapse before action must be taken. "Continuous" implies continuous action; however, in reality continuous monitoring enables no maintenance action to be taken until such time as trends indicate the need to do so. Therefore we recommend that where the maintenance interval is stated as "Continuous" it should be changed to read "Never" or "Not Applicable". 5. The Table 1A requirement of 3 months for Protection System Control Circuitry (Breaker Trip Coil Only) (except for UFLS or UVLS) should be omitted as it is not realistic. Recommend following the Table 1B requirement of 6 years (Trip testing) for this. Does 27 undervoltage monitoring of this circuit qualify as self monitoring?
Response: The SDT thanks you for your comments. **1. The requirement to which you refer has been removed. See FAQ IV-1-B (page 21) for a general discussion of documentation.** **2. The SDT has modified the standard to remove the requirement cited in your comment.** **3. See FAQ II-7-C (page 18) and FAQ II-8-E (page 19A).** **4. Continuous" is intended to clarify that the maintenance is being performed continuously via the monitoring system and the Activities portion of the table is intended to state those activities that are being performed by the monitoring system.** **5. The SDT has removed this requirement.**		
CPS Energy	No	While I agree for the most part, there are some activities that are unclear. 1. Specifically, the testing of voltage and current sensing devices, some of the trip coil testing, and some of the communications testing. If the trip coil is now going to be included in the definition of the protective

Organization	Yes or No	Question 2 Comment
		system, is the testing defined adequate? 2. The testing of the voltage and current sensing devices is not entirely clear.
Response: The SDT thanks you for your comments. **1. The listed activities are contemplated as minimum activities and do not preclude an entity from performing additional activities.** **2. See the Supplementary Reference Document, Section 15.2 (page 21) and FAQ II-3-A (page 19) for a discussion of this topic.**		
AECI	No	1. Tables 1a and 1b Station DC Supply: Requirement is to measure specific gravity and temperature of every cell. We believe that this test is unnecessary if voltage and internal resistance are measured. This test should only be required if other tests indicate a problem, or if the voltage and internal resistance tests are not performed. 2. Tables 1a and 1b Station DC Supply (Valve Regulated Lead-Acid Batteries): Will a limited discharge test be acceptable as a “performance or service capacity test” or is full discharge required? We believe a full discharge test will decrease battery life and suggest that only a limited discharge test be performed. 3. Tables 1a and 1b Station DC Supply (Vented Lead-Acid Batteries): What is the definition of “modified performance capacity test?”
Response: The SDT thanks you for your comments. **1. The SDT has modified the standard in consideration of your comment concerning station dc supply and has removed the requirement to measure specific gravity and temperature of every cell.** **2. The SDT does not feel that conducting a performance or service capacity test at the intervals prescribed in the standard will cause any appreciable decrease in battery life over the service life of the battery. The Protection System owner is responsible for maintaining a station dc supply that can perform as designed and conducting a performance or service capacity test will verify that a VRLA battery will satisfy the design requirements (battery duty cycle) of the dc system that a limited discharge test might not verify. If you are concerned that such a test may have implications on battery life, the standard provides an option to instead measure and trend internal cell/unit ohmic values on a 3-month interval.** **3. How to conduct a modified performance test for Vented Lead-Acid Batteries is explained in detail in various available reference books. For Vented Lead-Acid Batteries, it is a capacity test where the discharge rate(s) are modified to cover every portion of the battery’s duty cycle.**		
Puget Sound Energy	No	For all tables, PSE agrees with the majority of the minimum maintenance activities established. However, the Station DC supply maintenance activities raise concern. The requirement to test that the charger will provide full rated current versus output seems to be excessive. In many cases the charger is rated far in excess of the output needed to perform its function. Also PSE is not aware of a known industry test for these and it is

Organization	Yes or No	Question 2 Comment
		not an IEEE recommended standard. Finally, PSE is unclear whether this test would diminish the charger.
Response: The SDT thanks you for your comments. The SDT modified the standard in consideration of your comment regarding battery chargers. The maintenance activities for battery chargers have been modified to remove all activities except for verification of the float voltage.		
SERC (PCS)	Yes	We agree with the majority of the activities. Below is an example where clarification is needed. 1. “Verify proper functioning of the current and voltage circuit inputs from the voltage and current sensing devices to the protective relays” under “Voltage and Current Sensing Devices Inputs to Protective Relays.” How would this be done if no redundancy is available for cross-checking voltage and current sources? 2. In certain situations, “verify proper functioning” is not clear enough. Documentation of verification consistent with the entities procedures should be adequate to indicate compliance.
Response: The SDT thanks you for your comments. **1. The standard is prescribing what needs to be done, not how. Please refer to the Supplementary Reference Document Section 15.2 (page 21) and FAQ II-3-A (page 19) for examples and additional discussion.** **2. Documentation of verification consistent with your procedures is sufficient to “verify proper functioning”**		
TVA	Yes	Add clarifying statement from Table 1b for Protection System Control Circuitry (Trip Circuits) (UFLS/UVLS Systems Only) to the same section in Table 1a. Statement is “(Verification does not require actual tripping of circuit breakers or interrupting devices.)"
Response: Thank you for your comment. The SDT has modified the standard in consideration of your comment. The following was added to Table 1a: **Type of Component -** Control and trip circuits with electromechanical trip or auxiliary (UFLS/UVLS Systems Only) **Maximum Maintenance Interval -** 6 Calendar Years **Maintenance Activity** - Perform a complete functional trip test that includes all sections of the Protection System control and trip circuits, including all electromechanical trip and auxiliary contacts essential to proper functioning of the Protection System, except .that verification does not require actual tripping of circuit breakers or interrupting devices.		
JEA	Yes	If a communication system relies on a battery system independent of the "station battery", is this communication system battery under the same requirements as the "station battery"?
Response: Thank you for your comment. The proper functioning of such batteries will be addressed by the verification and monitoring of the communications system, and by addressing maintenance correctable issues related to maintenance of communication systems. See FAQ II-5-K (page		

Organization	Yes or No	Question 2 Comment
15).		
Bonneville Power Administration	Yes	
Electric Market Policy	Yes	
Entergy Services, Inc	Yes	
Georgia System Operations Corporation	Yes	
Oncor Electric Delivery	Yes	
Ontario Power Generation	Yes	
Operations and Maintenance	Yes	
Saskatchewan Power Corporation	Yes	
Western Area Power Administration	Yes	

3. Within Table 1a, the draft standard establishes maximum allowable maintenance intervals for the various types of devices defined within the definition of "Protection System", where nothing is known about the in-service condition of the devices. Do you agree with these intervals? If not, please explain in the comment area.

Summary Consideration: Most respondents disagreed with the specified maximum allowable intervals to some degree or another. The disagreements ranged over the full spectrum of activities specified in the Tables, and often corresponded to the disagreements related to the activities. The intervals within Table 1a were reconsidered (with minor changes – eliminating the 3-month control circuit activity) by the SDT when responding to the comments.

Organization	Yes or No	Question 3 Comment
Green Country Energy LLC	No	1) Protection System Control Circuitry (Trip Circuits) (except for UFLS or UVLS) also The maintenance activity causes excessive breaker operation, and the intrusive nature increases the risk of subsequent Misoperations on operating units. System configuration of many plants will require an extensive interruption of total plant production to complete the test. 2) Protection System Control Circuitry (Trip Circuits) (UFLS or UVLS systems only) The maintenance activity causes excessive breaker operation, and the intrusive nature increases the risk of subsequent Misoperations on operating units. System configuration of many plants will require an extensive interruption of total plant production to complete the test.
Response: The SDT thanks you for your comments. **1. The overall Protection System Control Circuitry can be addressed in segments, as long as all portions are verified or tested as required. Depending on the arrangement of the DC control circuit, it may be necessary to only trip the breaker itself once. See FAQ II-4-E (page 11).** **2. The overall Protection System Control Circuitry can be addressed in segments, as long as all portions are verified or tested as required. Depending on the arrangement of the DC control circuit, it may be necessary to only trip the breaker itself once. See FAQ II-4-E (page 11).**		
Public Service Enterprise Group Companies	No	1) Table 1a Station dc supply (that uses a battery and charger). The 6 year test requires that the charger perform as designed. PSE&G usually applies redundant battery chargers. PSE&G would like the drafting team to consider if it is appropriate to not require the 6 year battery charger tests if a battery owner uses primary and backup battery chargers. PSEG believes that the use of a redundant charger will maintain reliability at the same level or better level as provided by testing a single charger. 2) For protection system control circuits components (breaker trip coil only), suggest that a sub category with redundant trip coils be added with longer maintenance interval to allow for the reliability provided by

Organization	Yes or No	Question 3 Comment
		redundancy.
Response: The SDT thanks you for your comments. **1. The performance of the battery charger is critical to the performance of the protection system. The SDT has modified the standard to simplify the requirements related to maintenance of the battery charger. If condition-based maintenance is applied in accordance with Table 1b, the battery alarms could automatically (or manually) switch to the redundant charger. Redundancy may also provide more flexibility in addressing issues discovered during maintenance.** **2. Even with redundant equipment, it is essential that all equipment be tested according to the requirements of this standard to ensure proper function and to support the reliability advantages presented by redundancy. The requirements related to this subject have been extensively modified.**		
Ameren	No	1) The “zero tolerance” structure proposed combined with the large volume and complexity of Protection System components forces an entity to shorten their intervals well below maximum. We instead propose a calendar increment grace period in which a small percentage of carryover components would be tracked and addressed. For example, up to 10% of all breaker trip coils subject to the 3 month “verify breaker trip coil continuity” could carry over into the first month of the next period. And for example, up to 5% of an entity’s communication channel 6 year verifications could carryover into the next year. These carryover components would be addressed with high priority in that next calendar increment. There are many barriers to 100% completion or zero tolerance. Barriers include sheer volume, obtaining outages, resource availability, coordination, and documentation (over ten thousand components in our utility alone; taking a BES outage to permit maintenance can incur a greater reliability risk than delaying the maintenance; emergent issues such as major storms impact resource availability; coordination with interconnected neighbors, their resources and maintenance timing; record keeping errors or oversights; etc.) 2) Alternatively, components with intervals less than a year should be stated in terms of the number of times annually it should be performed, rather than a short duration interval. The expectation is that they would be roughly equally spaced throughout the year; for example quarterly instead of 3 months. Comment 1 grace period would still apply to components with maximum intervals of 1 year or greater. 3) Some of our maintenance intervals are shorter than maximum. Please confirm that documentation is only to be kept for two of the entity’s intervals, not two of the maximum interval. 4) Please add standard language or FAQ near 2D on p 18 that an entity can validly use an interval with % tolerance to achieve maintenance goals, as long as the applicable maximum interval is honored.
Response: The SDT thanks you for your comments. **1. The SDT is concerned that a “grace period”, if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a “grace**		

Organization	Yes or No	Question 3 Comment
period" would not conform to this directive. **2. Simply stating the number of times annually that these devices must be maintained, with a tacit expectation that the maintenance be spaced throughout the year, does not ensure that they will be tested thusly. To achieve the periodicity of the testing, it is essential that the requirement specify such periodicity. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive.** **3. The data retention has been modified in consideration of your comments. The revised language reads as follows:** The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous on-site audit date, whichever is longer. **4. You may define your program within the parameters expressed within the standard as long as you adhere both to your program and to the Standard.**		
Exelon Generation Company, LLC	No	1. All maintenance activities should include a "grace" period to allow for changes to a nuclear generator's refueling schedule and emergent conditions that would prevent the safe isolation of equipment and/or testing of function. "Grace" periods align with currently implemented nuclear generator's maintenance and testing programs. 2. Table 1a page 6 regarding the 3 Month "Protection System Control Circuitry (Breaker Trip Coil Only) (except for UFLS or UVLS)" states that the maintenance activity shall verify the continuity of the breaker trip circuit including the trip coil. There is unclear guidance on how this activity is to be performed, particular on generator output breakers. Does this activity imply actual trip testing of the breaker itself? If so, performing this type of activity with the generator on-line puts the unit at risk without any commensurate increase in reliability to the bulk electric system. If this is the case it is requested that this particular test is extended from 3 months to 24 months to align with nuclear generating units refueling cycle. If not, and this activity is simply verification of continuity by means of light indication; then please clarify in Table 1a.
Response: The SDT thanks you for your comments. **1. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document for a discussion on this issue.**		

Organization	Yes or No	Question 3 Comment
2. The SDT has removed this requirement.		
Entergy Services, Inc	No	1. A 3 month interval activity is likely to drive an entity to perform that activity every 2 months in a zero tolerance, 100% completion, mandatory compliance environment. There should be an allowance for a grace period on monthly designated activities, for instance a one month grace period, unless the intention is to have the activity performed more frequently than indicated. Additional guidance is needed on the monthly interval designations. Is it okay, for instance, to do all four tasks (3 month interval) at one time? Instinctively the answer should be "no", but if following the "calendar year" allowance, then maybe it is. Are we non-compliant on a 3 month interval task if we go one single day over the due date? Instinctively the answer should be "no", but some additional guidance should be provided. For example, the standard might be more understandable if it indicated that if the interval is "four per year" (or 3 month interval), then it is allowed to perform these tasks no less than 45 days apart from each other as long as four are done within a calendar year, etc. 2. We believe the 3 month trip coil task activity could actually shorten the life of the trip coil, introduce unpredictable trip coil failures, and increase the risk of an in-service failure of the trip coil if the verification is done by tripping the breaker each time. Increasing the risk of failure is counter-productive the intent of the standard.
Response: The SDT thanks you for your comments. **1. The standard specifies MAXIMUM allowable intervals for the various activities; entities must manage their program however they see fit to adhere to those intervals. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive.** **2. The SDT has removed this requirement.**		
MRO NERC Standards Review Subcommittee	No	A. It looks like for unmonitored systems, breaker trip coils are to be checked for continuity every 3 months. There is no mention of auxiliary relays. In the partially monitored and fully monitored sections, trip coils and auxiliary relays are lumped in the same category at 6 calendar years each. What happened to the aux relays in the unmonitored section? Also, note that the term "trip coils" is used, not "breaker trip coils" in the type of component category. B. The maintenance interval for Protection System Control Circuitry (Trip coils and Auxiliary relays) is 6 years, but the interval for relay output contacts is 12 years when these components are partially monitored. It seems that these things all have a similar reliability. If commissioning tests are done diligently, the trip DC availability is continuously monitored and the trip coil itself is continuously monitored, no functional tests should be needed. The only thing that would be done at PM time would be to ensure that the alarming method is still

Organization	Yes or No	Question 3 Comment
		functional.
Response: The SDT thanks you for your comments. **A. The SDT has removed this requirement.** **B. In your discussion (with continuous monitoring of the trip dc and trip coil), you have effectively established most of the monitoring to move to either Table 1b or even Table 1c. You are encouraged to carefully review the Monitoring Attributes for these higher levels of monitoring; if you satisfy the attributes, you may be able to further minimize hands-on maintenance.**		
NextEra Energy Resources	No	a. (i) Protective relays, (ii) Protection Control Circuitry (Trip Circuits) and (iii) Protection System Communications Equipment and Channels should be changed from 6 calendar years to 8 calendar years. Based on FPL Group's experience and Reliability Centered Maintenance (RCM) program, FPL Group has established an 8 year program and has found that an aggressive 6 year program would not substantially increase the effectiveness of a preventative maintenance program. b. Battery visuals should be changed from 3 months to 6 months. Electrolyte levels of today's lead-calcium batteries are relatively stable for a 6 month period compared to lead-antimony batteries used in the past. c. The maximum maintenance interval for communications equipment should be changed from 3 months to 12 months. Based on FPL Group's experience and RCM program, FPL Group has established a 12 month program that is effective. d. Additionally, NextEra Energy concurs with other entities comments concerning this question: Imposing inflexible maximum interval requirements has the same basic problems as imposing inflexible minimum task requirements. The inflexible "maximum interval" approach fails to recognize the harmful effects of over-maintenance and precludes the ability of entities to tailor their maintenance program based on their configurations and operating experience. The maximum interval approach also has same perverse consequences for entities with redundant systems as the minimum interval approach. e. Furthermore, the rigid maximum interval approach embodied herein does not sufficiently take into consideration common natural disaster situations. Several of the preventive maintenance tasks proposed in this standard have a maximum interval of 3 months, which is problematic under normal circumstances and unworkable when routine maintenance activities have a much lower priority than emergency repair and restoration. An interval as short as this does not provide a sufficient maintenance scheduling horizon to complete the tasks. The SDT could attempt to address this shortfall by modifying the draft to account for natural disaster situations. For example, the FERC-approved NERC reliability standard FAC-003 for Vegetation Management does include such allowances for natural disasters, such as tornados and hurricanes. However, even if that specific problem is addressed, the fundamental problems created by an

Organization	Yes or No	Question 3 Comment
		overly prescriptive maximum interval approach remains.
Response: The SDT thanks you for your comments. **a. The SDT believes that the 6-year maximum allowable intervals, to which you refer, are appropriate. The intervals within the standard are based on the experience of the SDT and of the NERC System Protection and Control Task Force (SPCTF). The SPCTF also validated these intervals via an informal survey that represented about 2/3 of the net-energy-for-load within NERC, and by comparison to IEEE surveys. See Supplementary Reference Document Section 8 (page 9). An entity may implement a Performance Based maintenance program if they wish to apply their experience.** **b. The SDT agrees that a healthy modern lead acid battery can go for extended periods of time beyond 3 months without requiring watering. However, checking cell electrolyte level not only indicates the need for battery watering, it is an indication of an individual cell's health and needs to remain at the Maximum Maintenance Interval of 3 months. To avoid the confusion that the Maintenance Activity listed in Table 1 was to water the battery at the specified 3 month interval, the Drafting Team has changed the wording of the Maintenance Activity from "verify proper" to "check" electrolyte level.** **c. The 3 month interval is for inspection of unmonitored equipment. The SDT felt that this is appropriate for carrier channels or for leased audio channels that have a chance of failure and would result in an overtrip or failure to trip if ignored. It is possible to extend the interval for performance based systems if the entity has applicable data.** **d. FERC Order 693 directs that NERC establish maximum allowable intervals. For entities that wish to establish a performance-based maintenance program using experience, the standard DOES allow for that.** **e. The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. The SDT has therefore defined the minimum activities necessary to implement an effective PSMP.**		
CenterPoint Energy	No	a. See CenterPoint Energy's comments made in response to question 2. Imposing inflexible maximum interval requirements has the same basic problems as imposing inflexible minimum task requirements. The inflexible "maximum interval" approach fails to recognize the harmful effects of over-maintenance and precludes the ability of entities to tailor their maintenance program based on their configurations and operating experience. The maximum interval approach also has same perverse consequences for entities with redundant systems as the minimum interval approach. b. Furthermore, the rigid maximum interval approach embodied herein does not sufficiently take into consideration common natural disaster situations. Several of the preventive maintenance tasks proposed in this standard have a maximum interval of 3 months, which is problematic under normal circumstances and unworkable when routine maintenance activities have a much lower priority than emergency repair and restoration. An interval as short as this does not provide a sufficient maintenance scheduling horizon to complete the tasks. The SDT could attempt to address this shortfall by modifying the draft to account for natural disaster situations. For example, the FERC-approved NERC reliability standard FAC-003 for

Organization	Yes or No	Question 3 Comment
		Vegetation Management does include such allowances for natural disasters, such as tornados and hurricanes. However, even if that specific problem is addressed, the fundamental problems created by an overly prescriptive maximum interval approach remains.
Response: The SDT thanks you for your comments. **a. The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. The SDT has therefore defined the minimum activities necessary to implement an effective PSMP.** **b. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue.**		
FirstEnergy	No	Although we agree with the proposed maintenance intervals, there may be extenuating circumstances beyond an entity's control that could delay maintenance on a particular protection system. We ask the SDT to consider adding a footnote to these intervals that allows a grace period of up to three months when outages necessary for maintenance must be delayed due to unusual system conditions or other issues where an outage would be detrimental to the entity's system.
Response: The SDT thanks you for your comments. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue.		
American Transmission Company	No	1. ATC is concerned that the proposed standard would result in entities being required to use outdated testing techniques and or practices. We believe that the standard should identify the "what" and not the "how". The identification of specific testing techniques and/or practices would likely result in entities being

Organization	Yes or No	Question 3 Comment
		prevented from implementing improved techniques and/or practices. (The standard would have to be updated and receive FERC approval before entities could test/implement improved testing techniques and/or practices.) 2. An example of the standard directing the how is with station batteries. The "specific gravity" test, proposed in the standard, is being used less or not at all by some registered entities because a more accurate method that is less intrusive and provides more accurate results has been developed. (This standard would basically require entities to go backwards in testing practices.)This standard should not prevent the use of improved techniques and/or practices.
Response: The SDT thanks you for your comments. **1. In consideration for your concern, the Drafting Team has revised Table 1 to identify more of what is required for the station dc supply activities and eliminated most of the "how to do it".** **2. All references to specific gravity and temperature testing have been removed from the revised standard.**		
City Utilities of Springfield, MO	No	CU agrees in general with many of the maximum maintenance intervals. However, we disagree with the necessity to verify the continuity of trip coils every 3 months. We would be interested to know what basis the committee used to arrive at all intervals. Furthermore, it is our opinion that even if a component is unmonitored, the interval should not surpass the manufacturer's recommendations.
Response: The SDT thanks you for your comments and has removed this requirement.		
ITC Holdings	No	1. Does the standard require that time or condition based maintenance programs monitor countable events to identify significant problems in particular relay segments, and then adjust the maintenance interval accordingly? 2. On page 6: Please clarify the use of "Calendar Year" Our understanding is that if a relay is maintained on August 31, 2003 on a 6 year interval, it will not be overdue until January 1, 2010. Is this correct?? 3. On Page 7: What is the basis for 18 months? We believe 2 calendar years would be more appropriate. 4. On Pages 6, 10: What is the basis of the 6 calendar year interval for functional trip tests? We request that this be changed to a 10 calendar year interval. We follow a 10 calendar year interval that has proven to be satisfactory. Decreasing the interval to 6 calendar years will result in a major increase in our maintenance expenses without a corresponding increase in reliability. 5. On Page 9: If it is being verified ok every 3 months, what is the basis of the 6 calendar year interval for Communication equipment? ITC communications systems are partially monitored and therefore required to

Organization	Yes or No	Question 3 Comment
		perform this testing every 12 years. However, ITC would like to know the basis of the 6 year interval for informational purposes. 6. On pages 6, 8, 11, 13, 14 and 19: The maximum maintenance interval (when the associated UVLS or UFLS system is maintained) should be shown as the actual “6 Calendar Years”.? 7. On Page 1 of Attachment A: Please provide an example in the reference of the proper way of adjusting the interval based on test results. 8. On Pages 7, 8, 12: It is our understanding that adequate maintenance can be achieved by performing either one of the two maintenance activities in cases where there is an “or”, is that correct? 9. On Page 14: For the bottom two rows on page 14 we believe there is a typo and it should read “Level 2” not “Level 1”. 10. On Page 13: Do power line carrier schemes that provide a remote alarm if a daily check back test fails, meet level 2 monitoring requirements? 11. In Table 1: What is the basis for the 6 year interval for the battery systems? This test would be an additional test for ITC. We would prefer to perform this additional test with the relay periodic maintenance on a 10 year interval.

Response: The SDT thanks you for your comments.

1. No, the standard does not require that countable events be analyzed for determination of intervals in time-based or condition-based maintenance programs. However, excessive poor operation may trigger additional activities as part of a corrective action plan per PRC-004 in response to Misoperations.

2. Your understanding is incorrect. A maintenance activity last completed in 2003 on a 6-year interval would next need to be maintained sometime in 2009. (See Supplementary Reference Document Section 8.4, page 13)

3. The SDT believes that 18-month is the appropriate interval, based on common industry practice.

4. The SDT believes that 6-years is the appropriate interval, based on common industry practice. For entities that wish to establish a performance-based maintenance program using experience, the standard DOES allow for that.

5. The 6 year interval is mostly driven by the needs of power line carrier channels and the use of analog auxiliary tuning components in the communications systems. The relay communications systems intervals were based on the experiences of SDT and NERC System Protection Committee Task Force members.

6. The SDT has modified the standard in consideration of your comment to include the specific intervals for the various components related to UFLS/UVLS, with the exception of the dc supply. The maintenance for the dc supply for UFLS/UVLS was left related to the maintenance of the

Organization	Yes or No	Question 3 Comment
UVLS/UFLS system because the SDT believed that this activity should be tied to the specific intervals needed for the relays. **7. See FAQ IV-3-H (page 26).** **8. You are correct in your statement that the Maintenance Activity of verifying that the station battery can perform as designed can be met by completing either of the two activities listed in Table 1 in the prescribed Maximum Maintenance Interval.** **9. Thank you. You are correct; these table entries have been modified accordingly.** **10. Yes. A remote alarm daily auto-check back as you describe satisfies the Level 2 monitoring attributes for channel performance in a power line carrier system.** **11. The SDT believes that extending the Maximum Maintenance Interval for station batteries beyond that listed in Table 1 would degrade the Protection System by not detecting compromises to the performance of the station dc supply during the extended interval.**		
Platte River Power Authority Maintenance Group	No	Electro-mechanical relays are historically out of tolerance well before the 6 year maximum allowable maintenance intervals defined within table 1a.
Response: The SDT thanks you for your comments. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals.		
Florida Municipal Power Agency, and its Member Cities	No	1. FMPA agrees in general with many of the maximum maintenance intervals; however we have been unable to determine what basis was used to arrive at the time based intervals provided in the tables. Further explanation would be appreciated 2. FMPA is concerned with the use of the term “continuous” in Table 1c. As stated, it would seem that, on loss of communications that would communicate the alarm, thereby causing a loss of “continuous” monitoring and alarming, the entity who invested in a reliability improving monitoring system would be found non-compliant with an infinitesimal maintenance period required for “continuous” monitoring. Therefore, FMPA recommends using “not applicable” or some other term in this column.
Response: The SDT thanks you for your comments. **1. The intervals within the standard are based on the experience of the SDT and of the NERC System Protection and Control Task Force (SPCTF). The SPCTF also validated these intervals via an informal survey that represented about 2/3 of the net-energy-for-load within NERC, and by comparison to IEEE surveys. See Supplementary Reference Document Section 8 (page 9).** **2. The SDT believes that the maintenance is indeed being done “continuously”. If the alarming method is not functional, you’ve fundamentally dropped back to Level 1 or Level 2 monitoring, depending on the component.**		

Organization	Yes or No	Question 3 Comment
E.ON U.S.	No	1. Generally, E.ON U.S. requests that the SDT provide the basis for the proposed changes in maintenance time lines. E ON U.S.'s existing maintenance intervals are based on actual operating experience. Not having been provided with the basis for the proposed intervals, the time lines appear arbitrary. E.ON U.S. currently has an 8-year interval for combustion turbines vs. the 6-year interval provided here. The E.ON U.S. interval is based on the Company's experience with this equipment. E.ON U.S. suggests that the SDT provide some consideration to individual entities historic practices. 2. It is difficult to track "18 months". Maintenance intervals should be in expressed in number of years. 3. E ON U.S. also does not understand the basis for the 3 months maintenance schedule on breaker trip coils. Typically, the circuit breaker closed indication is wired through the breaker trip coil. Thus there could not be a breaker closed indication without a good breaker trip coil. So, this test should be considered continuous monitoring which may not even require documentation except in case of failure.
Response: The SDT thanks you for your comments. **1. See Supplementary Reference Document, Section 8 (page 9). An entity's historical practices and results can be used to establish a performance-based maintenance program as described within the standard.** **2. The SDT believes that the 18-month interval is appropriate. If you wish, you may do these activities more frequently to aid in your maintenance tracking, as long as you adhere to the requirements within the standard.** **3. If this indication is local (for example, a lamp), 3-month inspections of the lamp state are necessary to satisfy the requirement. If the indication is an alarm to a location such as a control room, control center, etc, this may satisfy for either Level 2 or Level 3 monitoring as you suggest.**		
Transmission Owner	No	a. i) Protective relays, ii) Protection Control Circuitry (Trip Circuits) and iii) Protection System Communications Equipment and Channels should be changed from 6 calendar years to 8 calendar years. Based on FPL's experience and Reliability Centered Maintenance (RCM) program, FPL has established an 8 year program and has found that an aggressive 6 year program would not substantially increase the effectiveness of a preventative maintenance program. b. Battery visuals should be changed from 3 months to 6 months. Electrolyte levels of today's lead-calcium batteries are relatively stable for a 6 month period compared to lead-antimony batteries used in the past. c. The maximum maintenance interval for communications equipment should be changed from 3 months to 12 months. Based on FPL's experience and RCM program, FPL has established a 12 month program that is effective.
Response: The SDT thanks you for your comments.		

Organization	Yes or No	Question 3 Comment
a. The SDT believes that the 6-year interval is appropriate. An entity may implement a Performance Based maintenance program if they wish to apply their experience. **b. The SDT agrees that a healthy modern lead acid battery can go for extended periods of time beyond 3 months without requiring watering. However, checking cell electrolyte level not only indicates the need for battery watering, it is an indication of an individual cell's health and needs to remain at the Maximum Maintenance Interval of 3 months. To avoid the confusion that the Maintenance Activity listed in Table 1 was to water the battery at the specified 3 month interval, the Drafting Team has changed the wording of the Maintenance Activity from "verify proper" to "check" electrolyte level.** **c. The 3 month interval is for inspection of unmonitored equipment. The SDT felt that this is appropriate for carrier channels or for leased audio channels that have a chance of failure and would result in an overtrip or failure to trip if ignored. It is possible to extend the interval for performance based systems if the entity has applicable data.**		
Illinois Municipal Electric Agency	No	1. IMEA is concerned the maximum allowable maintenance intervals may be too prescriptive for transmission subsystems that essentially operate radially. 2. Please see comment under Question 7. 3. Given the magnitude of reliability-related initiatives currently in progress, additional time is needed to evaluate these intervals, particularly for communications equipment, dc supply, and UFLS relays.
Response: The SDT thanks you for your comments. **1. The intervals are established for Protection Systems on BES components. If you believe that some of your system components are not BES that is an issue relative to your region's BES definition.** **2. See response to comment under Question 7.** **3. An Implementation Plan is provided to allow systematic implementation of these intervals. If you are concerned about the time available to develop comments on posted drafts, be advised that the posting period is determined according to the NERC Reliability Standards Development Process. The SDT is providing the maximum comment time available.**		
PacifiCorp	No	No comment.
Duke Energy	No	1. Our comments are limited to Table 1a. More clarity is needed for many of the Maintenance Activities before assessing whether or not the intervals are reasonable. But as a general comment we would like to understand the basis used to develop all of the intervals, and how that basis compares with research done by the Electric Power Research Institute (EPRI). It is our understanding that NERC did an industry survey of maintenance intervals and we would like to see the results of that survey as well. Specific comments:

Organization	Yes or No	Question 3 Comment
		2. Protective Relays 6 calendar years is okay. 3. Voltage and Current Sensing Devices Inputs to Protective Relays We question the logic for a 12-year interval. Proper functioning should be verified at commissioning, and then anytime thereafter if changes are made in a PT or CT circuit. Additional periodic checks may be warranted as suggested in Table 1A, however no additional checking should be required where circuit configuration will inherently detect problems with a PT or CT. For example, PTs & CTs that are monitored through EMS or microprocessor relays will be alarmed when they are out of specification. 4. Protection System Control Circuitry (Breaker Trip Coil Only) (except for UFLS or UVLS) In locations where the continuity of the circuit is not monitored (via a light in the path or through a microprocessor relay) this would be a very complicated test, which could impact reliability, especially if done every three months. 5. Protection System Control Circuitry (Trip Circuits) (except for UFLS or UVLS) Need clarity on exactly what the activity is to include. We believe proving one output all the way to the trip coil is appropriate. Proving every output and every auxiliary contact, to the trip coil would be unnecessarily invasive and could impact reliability, even if done every 6 calendar years. 6. Protection System Control Circuitry (Trip Circuits) (UFLS/UVLS Systems Only) Interval is okay, but we disagree with tripping the breakers proving the output of the relay should be sufficient. Systems that have all load shed on distribution circuits should require trip output be confirmed but should not be required through to the trip coil due to constraints in tying distribution load. 7. Station dc supply (that has as a component any type of battery) 3 month and 18 month intervals are probably okay, depending on what is required to “verify continuity and cell integrity of the entire battery” and “inspect the structural integrity of the battery rack”. 8. Station dc supply (that has as a component Valve Regulated Lead-Acid batteries) 3 calendar years and 3 month intervals are probably okay, depending on what is required for the “performance or service capacity test”. 9. Station dc supply (that has as a component Vented Lead-Acid batteries) 6 calendar year and 18 month intervals are probably okay, depending on what is required for the “performance, service or modified performance capacity test”. 10. Protection system communication equipment and channels 3 months and 6 calendar years seem reasonable, depending upon what is included in the substation inspection, and what is required for power-line carrier systems. 11. UVLS and UFLS relays that comprise a protection scheme distributed over the power system Can’t comment on the 6 calendar year interval until we get more clarity regarding the meaning of “distributed over

Organization	Yes or No	Question 3 Comment
		the power system".
Response: The SDT thanks you for your comments. **1. See Supplementary Reference Document, Section 8 (page 9).** **2. The SDT thanks you for your support.** **3. For unmonitored systems, the SDT believes that the interval specified in Table 1a is appropriate. If alarming is available for anomalies, you may be able to use Table 1c with continuous monitoring.** **4. Table 1a has been modified to remove the activities to which you refer.** **5. See Supplementary Reference Document, Section 15.3 (page 22).** **6. The requirements relating to Protection System Control Circuitry for UFLS/UVLS only do not require tripping of the breaker.** **7. Thank you for agreeing with the Maximum Maintenance intervals associated with the Maintenance Activities. The SDT has modified the standard concerning the requirement to verify cell integrity (See FAQ II-5-C, page 12), and continuity (See FAQ II-5-D, page 13) and inspecting for the structural integrity of the battery rack (See FAQ II-5-H, page 15).** **8. How to conduct a performance and service capacity test for Valve Regulated Lead-Acid batteries are explained in detail in various available reference books. One of the options available to the Protection System owner who is responsible for maintaining a station dc supply that can perform as designed is to conduct a performance or service capacity test within the Maximum Maintenance Interval of Table 1 that will verify that a VRLA battery will satisfy the design requirements (battery duty cycle) of the dc system.** **9. How to conduct a performance service or modified performance capacity test for Vented Lead-Acid Batteries is explained in detail in various available reference books.** **10. These intervals are for power line carrier channels as well as other types of communications channels.** **11. See FAQ II-7-C (page 19).**		
Electric Market Policy	No	Recommend that all Level 1 three-month maintenance intervals be changed to a quarterly based system where only 4 inspections are required per year. Given a 3 month maximum interval, activities would need to be scheduled every 2 months, which would result in six inspections per year. Our experience of four inspections per year has proven to be successful.
Response: The SDT thanks you for your comments. The SDT believes that the "3 Calendar Month" interval is necessary to maintain the periodicity of the maintenance activities. "Once per calendar quarter" would allow up to a 6-month practical interval, which would not maintain this periodicity. This DOES permit entities to use four inspections per year provided that they carefully manage their maintenance activities.		

Organization	Yes or No	Question 3 Comment
SERC (PCS)	No	Recommend that all Level 1 three-month maintenance intervals be changed from 3 months to quarterly. Given a 3 month maximum interval an entity would need to schedule these tasks every 2 months. This would result in six inspections per year. In the experience of many of our utilities, four inspections per year have proven to be successful.
Response: The SDT thanks you for your comments. The SDT believes that the "3 Calendar Month" interval is necessary to maintain the periodicity of the maintenance activities. "Once per calendar quarter" would allow up to a 6-month practical interval, which would not maintain this periodicity. This DOES permit entities to use four inspections per year provided that they carefully manage their maintenance activities.		
Indianapolis Power & Light Co.	No	See comments in number 2 above.
Response: The SDT thanks you for your comments. See response to comments in Question 2.		
Austin Energy	No	See item # 10 Comments
Response: The SDT thanks you for your comments. See Question #10 Response		
Wolverine Power Supply Cooperative, Inc.	No	See question 2 response
Response: The SDT thanks you for your comments. See Question #2 Response		
SCE&G	No	Several maximum maintenance intervals are 3 months. Since this is an absolute maximum period, entities would need to schedule on a 2 month basis to assure the 3 month maximum is met, i.e., 6 times per year. We recommend that 3 month periods be increased to 4 months which allows scheduling every 3 months. Other methods of achieving the same result are to state periodic requirements of quarterly or 4 times per year.
Response: The SDT thanks you for your comments. The SDT believes that the "3 Calendar Month" interval is necessary to maintain the periodicity of the maintenance activities. "Once per calendar quarter" or "four times per year" would allow up to a 6-month practical interval, which would not maintain this periodicity. This DOES permit entities to use four inspections per year provided that they carefully manage their maintenance activities.		
Wisconsin Electric	No	Similar to comments in #7 above: It is our practice on distribution-level protection systems to utilize a 6 year interval plus/minus 1 year to accommodate potential scheduling conflicts. This is consistent with other LSE's relay testing practices as well. Thus the potential 7 year maintenance interval would be a violation of the draft

Organization	Yes or No	Question 3 Comment
		requirements. The maintenance intervals in this standard should be increased accordingly for distribution protection system equipment.
Response: The SDT thanks you for your comments. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document for a discussion on this issue.		
Pepco Holdings Inc.	No	Table 1a requires verification of the continuity of the breaker trip circuit every three months in the absence of a trip coil monitor. Recommend maintenance interval to match that for other protection system control circuitry (6 years).
Response: The SDT thanks you for your comments. The SDT has modified the standard to remove the requirement to which you refer.		
Nebraska Public Power District	No	Table 1a, for Station DC supply (that has as a component - Valve Regulated Lead-Acid batteries) establishes a Maximum Maintenance Interval of 3 Calendar Years for the following Maintenance Activity: Verify that the station battery can perform as designed by conducting a performance or service capacity test of the entire battery bank. What is the basis for this interval? NPPD's experience indicates that a 5 Year interval is adequate, especially during the early service life of the battery bank, with increasing frequency as the bank ages.
Response: Thank you for your comment concerning the Maximum Maintenance Interval for Valve Regulated Lead-Acid batteries (VRLA). Due to the failure mode and designed service life of VRLA batteries compared to a Vented Lead-Acid batteries, the SDT believes that extending capacity testing of a VRLA battery beyond the maximum maintenance interval of 3 calendar years in Table 1 cannot be justified regardless of what the battery manufacturers of VRLA batteries recommend. This is especially true in the later periods of service life beyond 3 calendar years as noted by many utilities requiring total replacement of their VRLA batteries after 4 years of service. It appears that your practices are actually addressing Vented Lead Acid batteries, rather than Valve Regulated Lead-Acid batteries.		
Dynegy	No	The 3 month interval in Table 1a for verification of the continuity of the breaker trip circuit is only feasible if this verification can be done by inspection versus testing (see Response to Question 2).
Response: The SDT thanks you for your comment and has removed the requirement.		

Organization	Yes or No	Question 3 Comment
Southern Company	No	1. The 3 month intervals specified for the trip coil monitoring and communication circuit testing are too frequent. Our experience is that trip coils rarely burn open and don't need to be checked this often. If no monitoring currently exists, manually checking the circuit (until a time where monitoring can be installed) may inadvertently cause a trip. This adds risk to the reliability. Thus, requiring the trip circuits to be tested every 3 months may reduce the reliability of the BES. 2. Protection System Control Circuitry (Breaker Trip Coil Only) (Except for UFLS or UVLS) In order to reduce the risk of reducing Bulk Electric System reliability a better time interval for testing un-monitored trip coils would be 12 months. This may need to be 24 months for Nuclear Generating units. 3. Some allowance for a grace period (beyond the specified intervals) should be considered for all classifications. Outage schedules are known to change unexpectedly due to unforeseen circumstances. A grace period tolerance of +25% for specified maintenance intervals less than 12 months and of +1yr for those intervals specified as greater than 12 months is recommended. Typically at a nuclear plant a grace period is allowed by plant procedures. This grace period is defined as an additional 25 percent of the original schedule interval for the task. The grace period is provided as reasonable flexibility to allow for alignment with surveillance activities and equipment maintenance outages and to better manage the use of station resources. Some maintenance activities will require an outage to perform the work. Refueling outages are typically performed on an 18 month or 24 month refueling cycle. However, refueling outages do not always fall exactly on that interval. It is possible that the duration between one outage to the next may exceed 18 or 24 months. For activities that are required to be complete on a calendar year cycle this should not be an issue since the outages are normally scheduled several months prior to the end of the year. However, if the interval is a monthly interval there could be a problem with scheduling the maintenance such that it does not impact planned maintenance activities, surveillance requirements, and station resources. 4. Tables 1a, 1b and 1c have several instances where inspection and testing of DC circuits or components has a specified interval of 18 months. At nuclear generating stations, such tests on station battery banks and associated chargers incur unacceptable risk if performed with the unit on line and a unit outage is required for this testing. A number of nuclear plants are on two-year shutdown cycles and we request that the 18 month intervals be changed to two (2) (calendar) year intervals to accommodate this. 5. Protection System Control Circuitry (Breaker Trip Coil Only) (Except for UFLS or UVLS) Based on past performance, a complete functional test trip every 6 years is not warranted. This complete functional test introduces additional risk to our maintenance program, not only from a human error perspective, but also from the additional frequency of switching and outages required. Our experience has shown that 12 years is an appropriate maximum time interval (rather than 6 years.)
Response: The SDT thanks you for your comments.		

Organization	Yes or No	Question 3 Comment
1. The SDT believes that such maintenance of the communications will primarily be performed by inspection monitoring lamps and so forth. The trip coil requirements to which you refer have been removed. **2. This activity is primarily inspection-based, involving no invasive testing. The stated intervals seem appropriate.** **3. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 (page 9) of the Supplementary Reference Document for a discussion on this issue.** **4. All Maintenance Activities listed in Tables 1a, 1b, and 1c related to the station dc supply that have a Maximum Maintenance Interval shorter than two (2) (calendar) years are necessary inspection, checking or verification activities routinely performed on the station dc supply with it in service and without posing an unacceptable risk. The Drafting team feels that to extend these activities beyond their Maximum Maintenance Intervals listed in Table 1 would jeopardize the station dc supply.** **5. The SDT believes that the 6-year interval for this activity is appropriate. If you experience supports a longer interval, the standard permits you to utilize Performance-Based maintenance.**		
AEP	No	The availability to perform maintenance of many protection systems is dictated by the load or customer that is connected. Many of these industrial customers, who are outside the jurisdiction of NERC requirements, operate 24X7 and see the outages required for maintenance as a nuisance and a loss of revenue. How can the owner be held non-compliant for not meeting the intervals when they may not control the timing? Comments expanded in question 10 responses.
Response: The SDT thanks you for your comments. This non-compliance would be addressed via contract law; these contracts are described in the Statement of Compliance Registry.		
US Bureau of Reclamation	No	The definition of Protection System components does not add clarity. The standard proposes including stations service transformers for generation facilities, however, the protection system definition does not include those elements. The inclusion of station service transformers would only be appropriate if the protection associated with the transformer results in the tripping of a transmission element.
Response: The SDT thanks you for your comments. The applicability to station service transformers emphasizes the impact of those components on the operability of the associated generator. They are not themselves Protection System components; however, maintenance of the Protection System		

Organization	Yes or No	Question 3 Comment
components on those system elements is required per the Standard. See FAQ III-2-A (page 20).		
Ohio Valley Electric Corp.	No	The documentation requirements for the inspection activities with three month intervals are oppressive and should not be a part of the protection system maintenance standard.
Response: The SDT thanks you for your comments. The SDT disagrees; it is left to the entity to adopt effective methods to document these activities.		
CPS Energy	No	1. The first problem that I have is the 3 Months for the Protection system communications equipment and channels component. My main concern with this interval is that it is so extremely short and I am concerned that there may not be any rational behind it. What studies, surveys, or statistical data were used to determine that 3 months is necessary to protect the reliability of the BES? It doesn't make sense that a communications signal needs to be checked every 3 months but the protective relay that utilizes that scheme needs to be checked at most only every 6 years. 2. What concerns me the most with the 3 month interval for my company is with on-off power line carrier DCB schemes? We only have these schemes on tie lines, and it can be difficult to implement a checkback system with another utility who might utilize different carrier equipment. This type of scheme is also intended to be inherently insecure and is frequently more or less tested with faults in the system. The SPCTF should do surveys to determine what is presently done with these type of systems or provide some other rationale for the communication requirements. It is not totally clear from the documents, but it appears that the only way to avoid the 3 month check for an on-off power-line carried DCB scheme is to have an automated check back scheme. Is this correct? Or is alarming from the carrier equipment adequate? 3. My second problem is with the 6 year maximum maintenance interval for the breaker trip coil in tables 1b and 1c. By having to verify that each breaker trip coil is electrically operated, you might as well perform a functional test to test the protection system control circuitry. Electrically operating the trip coil tests the breaker as much as it test the actual trip coil. Also, if you have a primary and secondary trip coil, is it really necessary to test this often? What studies or statistical data were used to determine that testing the breaker trip coils every 6 years is necessary to protect the reliability of the BES? 4. My third problem is with the intervals requirements for the UVLS/UFLS systems. Other than testing and calibration of electromechanical UVLS/UFLS, most other tests probably should require at most 10 years for these types of systems. These systems don't require the performance level of most other systems as stated in the supplementary reference. The testing and calibration of electromechanical UFLS should possibly be even shorter than the 6 year requirement due to problems with drift with these type of relays. What studies, surveys, or statistical data were used to determine the intervals in related to UFLS/UVLS.?
Response: The SDT thanks you for your comments.		

Organization	Yes or No	Question 3 Comment
1. The 3 month intervals are for unmonitored equipment and are based on experience of the relaying industry represented by the SDT, the SPCTF and review of IEEE PSRC work. Relay communications using power line carrier or leased audio tone circuits are prone to channel failures and are proven to be less reliable than protective relays. 2. The automated check back systems are common ways to verify the integrity of the relay communication channel. It would only be moved to Level 2 if the check back test is monitored remotely and the tests are run daily. Without check back equipment, it will be necessary to have personnel at both ends and manually initiate a signal and verify that the remote equipment operates. 3. In the experience of the SDT and the NERC SPCTF, the 6-year interval is appropriate. The SPCTF also conducted an informal survey of entities representing approximately 2/3 of the NERC net-energy-for-load and a review of IEEE surveys to validate these intervals. See the Supplementary Reference Document, Section 8 (page 9). 4. In the experience of the SDT and the NERC SPCTF, the 6-year interval is appropriate. The SPCTF also conducted an informal survey of entities representing approximately 2/3 of the NERC net-energy-for-load and a review of IEEE surveys to validate these intervals. See the Supplementary Reference Document, Section 8 (page 9). The maintenance of the other Protection System components associated with UFLS/UVLS is specifically stated to correspond with the intervals for the relays themselves.		
Consumers Energy Company	No	1. The interval for Protection System Control Circuitry (breakers trip coil) should be set at 12 years since this is a scheme test. This test requires testing of the circuit and not just the coil. 2. The interval for Protection System Control Circuitry (trip circuit) should be set at 12 years since this is a scheme test. The Protection System Control Circuitry (trip circuit) test would require tripping off customers on radial distribution circuits which is not acceptable. 3. The interval for a station battery service test (lead acid) should be set at 5 years based on NFPA 70B.
Response: The SDT thanks you for your comments. 1. The SDT believes that the intervals indicated in the standard are appropriate. The standard allows the use of Performance-Based maintenance if your experience supports it. 2. The SDT believes that the intervals indicated in the standard are appropriate. The standard allows the use of Performance-Based maintenance if your experience supports it. The standard applies only to Protection Systems on BES components as established by your regional BES definition. 3. NFPA 70B is a recommended practice which is voluntary, and is not a standard that establishes any requirements that must be measurable. NERC standard PRC-005 requirements are loosely aligned with some of the NFPA standards. However, the Maximum Maintenance Intervals required in PRC-005-2 were established to be measurable and enforceable. If an owner chooses to perform the Maintenance Activities outlined in Table 1 of the standard at a lesser interval the owner is free to do so.		
RRI Energy	No	1. The intervals need to be defined on a calendar quarters or calendar years, especially for intervals listed as 3 months. The demonstration of maintenance on rolling three-month intervals will be an onerous record

Organization	Yes or No	Question 3 Comment
		keeping task, particularly when relying upon planning and tracking software that scheduled recurring tasks on the same day of an interval. 2. Given the magnitude of the number of trip circuits, the requirements set an un-acceptable trap of non-compliance from a record keeping perspective. The resources required to keep and maintain flawless records are too much to justify the intervals. A non-compliance is the result if the breakers that happen to be in an open state when the officially "documented" inspection is recorded and is missed by accidental oversight on follow-up. If the requirement remains, it should be waived for any breaker that is operated during the defined interval.
Response: The SDT thanks you for your comments. **1. The SDT believes that the "3 Calendar Month" interval is necessary to maintain the periodicity of the maintenance activities. "Once per calendar quarter" or "four times per year" would allow up to a 6-month practical interval, which would not maintain this periodicity. This DOES permit entities to use four inspections per year provided that they carefully manage their maintenance activities.** **2. The dc control circuit maintenance to which you refer has been removed from the standards. The SDT disagrees that the record keeping is excessively burdensome; it is left to the entity to adopt effective methods to document these activities.**		
Progress Energy	No	The rational for microprocessor-based relay intervals is examined, but all others are strictly based on industry weighted average of survey results. We believe the team should use a more empirical, documented approach to determining these intervals, as many companies have longer intervals that they currently have documented for their basis. If these have been accepted as satisfactory in previous audits, why should they be required to change just to meet an arbitrary number?
Response: The SDT thanks you for your comments. The standard permits entities to use Performance-based maintenance if they have documented experience which supports doing so.		
Northeast Power Coordinating Council	No	1. We question whether any maintenance activity should be as long as 12 years. Considering the rate of change in personnel and technology, the working group should reduce the time period by redefining the requirement if necessary, or eliminate the standard requirement. 2. In addition, the DC components have too many tests at confusing intervals. Confusion will make it difficult to implement or follow the exact method used.
Response: The SDT thanks you for your comments. **1. In the experience of the SDT and the NERC SPCTF, the intervals within the standard are appropriate. The SPCTF also conducted an informal survey of entities representing approximately 2/3 of the NERC net-energy-for-load and a review of IEEE surveys to validate these intervals. (See**		

Organization	Yes or No	Question 3 Comment
Supplementary Reference Document, Section 8.4, page 13) **2. The SDT has modified the standard in consideration of your comments and simplified the maintenance activities associated with dc supplies.**		
Detroit Edison	No	What is the basis for the three month interval for verifying breaker trip coil continuity? Will the investment required to facilitate this really result in the presumed expected increased reliability?
Response: The SDT thanks you for your comments and has removed the requirement.		
Manitoba Hydro	No	1. When we have redundant digital relay system that would fall under Level 1c category with a 12 year maintenance cycle, but the Protection System Control Circuitry is non-monitored so it falls under Level 1a, with a 6 year maintenance cycle. We will have to complete relay maintenance and trip testing every 12 years and trip testing only every 6 years, therefore we must complete trip testing twice as often as we are doing the maintenance. We feel that relay maintenance and trip testing should be completed at the same frequency. 2. The Protection System Control Circuitry (Breaker Trip Coil) checks every three months is too excessive. These circuits are checked during trip testing of the Protection scheme, at the 6 or 12 year interval. 3. If we have a redundant digital relay system, using a IEC61850 communication from the relay to a common breaker aux trip relay, what level does this system fall under?
Response: The SDT thanks you for your comments. **1. Whether relay systems are redundant are immaterial in determining appropriate maintenance intervals. The SDT believes that the intervals established in the standard are appropriate. The Tables have been revised extensively; the SDT invites you to review the revised Tables to determine how they affect your system.** **2. The requirement to which you refer has been removed from the Table.** **3. Whether relay systems are redundant are immaterial in determining appropriate maintenance intervals. You will need to evaluate all components to determine applicable maintenance activities; the digital relays MAY fall under Table 1c, but other components may fall under any of the Tables.**		
Xcel Energy	No	Within the tables, several components related to UFLS/UVLS systems have an interval of “when the associated UVLS or UFLS system is maintained.” Yet, there is no maximum interval established for a UVLS or UFLS system. We feel this item should be clarified. If the intent of the SDT is to tie the testing to when the UFLS/UVLS relays are maintained, so that all components are tested at the same time, then this should be made clear. One possible resolution would be to change the interval to read: “when the associated UVLS/UFLS relays are maintained”.

Organization	Yes or No	Question 3 Comment
Response: The SDT thanks you for your comments. The interval for the UVLS or UFLS system relays is established within Table 1a, Table 1b, and Table 1c. The intent of the SDT is to facilitate concurrent maintenance of all components associated with these systems at a common location.		
AECI	No	1. Comments: Table 1a 3 months for protection system coil check out seems extreme. Should be at least 1 year. 2. Same as comment 4 for the communication checkout on page 9.
Response: The SDT thanks you for your comments. **1. The SDT has modified the standard to remove the requirement to which you refer.** **2. See response to your question 4 comment on communication checkout.**		
Puget Sound Energy	Yes	PSE appreciates the explanation of calendar provided in the supplementary reference on page 14. Further clarity would be gained by an example that is not at the end of a calendar year. For example if a relay was maintained June 15, 2008, would it be due for maintenance again no later than June 30, 2014 or December 31, 2014.
Response: The SDT thanks you for your comments. For your example, the maintenance would have to be completed within 2014.		
Bonneville Power Administration	Yes	
ENOSERV	Yes	
Georgia System Operations Corporation	Yes	
Lower Colorado River Authority	Yes	
Oncor Electric Delivery	Yes	
Ontario Power Generation	Yes	
Operations and Maintenance	Yes	

Organization	Yes or No	Question 3 Comment
Otter Tail Power	Yes	
Saskatchewan Power Corporation	Yes	
TVA	Yes	
Western Area Power Administration	Yes	

4. Within Tables 1b and 1c, the draft standard establishes parameters for condition-based maintenance, where the condition of the devices is known by means of monitoring within the substation or plant and the condition is reported. Do you agree with this approach? If not, please explain in the comment area.

Summary Consideration: Most respondents agreed with the general approach regarding condition-based maintenance, many of them with questions and/or comments. Many of the comments requested clarification of any of a variety of specific provisions within Tables 1b and 1c, and revisions were made to the Tables to present the information more clearly. The activities for control circuits and for dc supply were considerably re-worked.

Organization	Yes or No	Question 4 Comment
Green Country Energy LLC		No Preference at this time.
Exelon Generation Company, LLC	No	1. Please provide more clarification on what constitutes "partially monitoring." For example, is a computer auxiliary contact alarm count as partial monitoring? Would a common alarm between relays meet the definition of partial monitoring? 2. All maintenance activities should include a "grace" period to allow for changes to a nuclear generator's refueling schedule and emergent conditions that would prevent the safe isolation of equipment and/or testing of function. "Grace" periods align with currently implemented nuclear generator's maintenance and testing programs. 3. Table 1b Station dc supply (that has as a component valve regulated lead-acid batteries) should provide an additional optional activity for "Total replacement of battery at an interval of four (4) years. 4. There seems to be a disconnect between the monitoring attribute and maintenance activity. For example, the monitoring attribute "Monitoring and alarming of the station dc supply voltage/detection and alarming of dc grounds" has the maintenance activity "verify that the station battery can perform as designed by conducting a performance or service capacity test of the entire batter bank. (3 calendar years) or " Verify that the station battery can perform as designed by evaluating the measure cell/unit internal ohmic values to station battery baseline (3 months)." The maintenance activity does not support the monitoring attribute. 5. If an entity has implemented Table 1b and/ or Table 1c, is there an acceptable length of time that the monitoring equipment can be out of service without falling back to Table 1a requirements?
Response: The SDT thanks you for your comments.		

Organization	Yes or No	Question 4 Comment
1. A common alarm would meet the definition of partially monitored. See FAQ V-3-A (page 38). **2. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue.** **3. The SDT believes that total replacement of a VRLA battery set at an interval of four (4) years in lieu of not conducting a capacity test at the maximum maintenance interval of 3 calendar years, or evaluating the measured cell/unit internal ohmic values to the station battery's baseline at the maximum maintenance interval of 3 months would put the owner of the battery set out of compliance with the standard. The SDT believes the three calendar year Maximum Maintenance Interval for conducting a capacity test (listed in Table 1) cannot be exceeded. If an owner does a total replacement of the battery within a three calendar year interval from initial installation of a VRLA battery set, the owner will be compliant with the standard. Extending the time that a VRLA goes beyond the Maximum Maintenance Interval in Table 1 without verification that it can perform as designed is not adequate to insure that the station battery will perform reliably.** **4. The monitoring attributes describe "what you know of the component via the monitoring", while the activities describe what must be done relative to the "things you don't know". Therefore, it's expected that the attributes and activities will be dissimilar.** **5. The equipment used to monitor the alarms must be returned to service within the shortest Table 1a interval of the monitored components. For example, if monitoring is used to defer the 3-month Table 1a maintenance activity related to Protection System Control Circuitry, the monitoring function must be returned to service within 3 months. This has been added to Table 1b and Table 1c as a requirement.**		
American Transmission Company	No	1. ATC does not believe that there is a relay, on the market today, that has the ability to fully monitor itself as described in Table 1c. We believe that Table 1c should be deleted. (Table 1b could cover any device that has the ability to fully monitor if such a device is developed in the future.) ATC does not believe that NERC Reliability Standards should be used as an enticement for manufacturers to develop specific devices. 2. Under the "General Description" in Table 1c, there is a reporting requirement identifying a 1 hour window. ("must be reported within 1 hour or less of the maintenance-correctable issue occurring, to the location where action can be taken.") ATC believes that the team needs to define if this action is a phone call or physically verify the maintenance correctable issue which is occurring.
Response: The SDT thanks you for your comments. **1. Your observation may be accurate at the present time and is not limited to protective relays. The standard was developed with future improvements**		

Organization	Yes or No	Question 4 Comment
in technology and practices in mind. **2. This reporting requirement is intended to be by whatever means is available, to a location where resolution of the maintenance-correctable issue can be initiated.**		
Duke Energy	No	For utilities like us with large numbers of relays it's too complicated, which drives us back to Table 1a.
Response: The SDT thanks you for your comments. The standard was written with enough flexibility to allow entities to make the best business decision for their situation. Some entities may decide that Table 1a is the best fit for their situation.		
AEP	No	How would the failure of a SCADA system affect the ability to take advantage of monitoring?
Response: The SDT thanks you for your comments. **It doesn't, as long as the SCADA system is returned to service within the shortest Table 1a interval of the monitored components. For example, if monitoring is used to defer the 3 month Table 1a maintenance activity related to Protection System Control Circuitry, the monitoring function must be returned to service within 3 months. This has been added to Table 1b and Table 1c as a required attribute for the associated type of protection system component.**		
Illinois Municipal Electric Agency	No	IMEA supports comments submitted by Florida Municipal Power Agency regarding use of the word "every" in Table 1c.
Response: The SDT thanks you for your comments. See response to FMPA.		
Pepco Holdings Inc.	No	Monitoring and alarming of the station dc supply and detection and alarming of dc grounds are required to qualify for Level 2 monitoring of battery / dc systems. While the presence of dc ground may affect protection and control operations, they do not affect any of the systems for which dc ground alarming is listed as a monitoring criteria. Recommend removing this criterion from the battery & dc system monitoring criteria and adding it as a maintenance activity, with frequency of testing based on presence of detection / alarming.
Response: The SDT thanks you for your comments. The dc ground alarm may identify a maintenance correctable issue, which must be resolved according to Requirement R4. The SDT believes that dc ground detection is usually a part of battery maintenance; this is sometimes even included in the battery charger.		
Electric Market Policy	No	Recommend that all Level 2 three-month maintenance intervals be changed to a quarterly based system where only 4 inspections are required per year. Given a 3 month maximum interval, activities would need to be scheduled every 2 months, which would result in six inspections per year. Our experience of four

Organization	Yes or No	Question 4 Comment
		inspections per year has proven to be successful.
Response: Thank you for your comments .SDT believes that the "3 Calendar Month" interval is necessary to maintain the periodicity of the maintenance activities. "Once per calendar quarter" or "four times per year" would allow up to a 6-month practical interval, which would not maintain this periodicity. This DOES permit entities to use four inspections per year provided that they carefully manage their maintenance activities.		
SERC (PCS)	No	Recommend that all Level 2 three-month maintenance intervals be changed from 3 months to quarterly. Given a 3 month maximum interval an entity would need to schedule these tasks every 2 months. This would result in six inspections per year. In the experience of many of our utilities, four inspections per year have proven to be successful.
Response: The SDT thanks you for your comments. SDT believes that the "3 Calendar Month" interval is necessary to maintain the periodicity of the maintenance activities. "Once per calendar quarter" or "four times per year" would allow up to a 6-month practical interval, which would not maintain this periodicity. This DOES permit entities to use four inspections per year provided that they carefully manage their maintenance activities.		
Wolverine Power Supply Cooperative, Inc.	No	See question 2 response
Response: The SDT thanks you for your comments. See Question 2 response.		
SCE&G	No	Several maximum maintenance intervals are 3 months. Since this is an absolute maximum period, entities would need to schedule on a 2 month basis to assure the 3 month maximum is met, i.e., 6 times per year. We recommend that 3 month periods be increased to 4 months which allows scheduling every 3 months. An alternate method of achieving the same result is to state periodic requirements of quarterly or 4 times per year.
Response: The SDT thanks you for your comments. SDT believes that the "3 Calendar Month" interval is necessary to maintain the periodicity of the maintenance activities. "Once per calendar quarter" or "four times per year" would allow up to a 6-month practical interval, which would not maintain this periodicity. This DOES permit entities to use four inspections per year provided that they carefully manage their maintenance activities.		
Detroit Edison	No	Table 1b indicates that this (level 2) includes all elements of level 1 monitoring. However, level 1 is constantly referred to as unmonitored in other places.
Response: The SDT thanks you for your comments and modified Table 1b to address your comment by removing this reference from the header of the table.		

Organization	Yes or No	Question 4 Comment
Southern Company	No	1. Table 1b should allow self-monitored circuits that are not alarmed but are monitored and logged by personnel daily or more often. Many plants and substations have personnel that do in person checks of unmanned control rooms. This is the equivalent of “Protection System components whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for alarmed failures.” For example, dc system ground potential lights and dc system volt meters exist on most control room bench boards or exist in the digital control systems at generating stations. These devices are monitored by operators in manned control rooms. 2. On Table 1b, Protection System Control Circuitry (Trip Coils and Auxiliary Relays), the monitoring component calls for “Monitoring and alarming of continuity of trip coil(s).” Clarify that “trip coil(s)” excludes Breaker Failure Initiate relay coil(s). 3. On Table 1b, Protection System Control Circuitry (Trip Coils and Auxiliary Relays) Experience has shown that electrically operating fully monitored breaker trip coils, auxiliary relays, and lockout relays every 6 years is not warranted. This testing introduces risk from a human error perspective as well as from additional switching and clearances required. We recommend eliminating this maintenance requirement from Table 1b. 4. On Table 1c, Protection System Control Circuitry (Trip Coils and Auxiliary Relays) Experience has shown that electrically operating fully monitored breaker trip coils, auxiliary relays, and lockout relays every 6 years is not warranted. This testing introduces risk from a human error perspective as well as from additional switching and clearances required. We recommend changing this maximum maintenance interval to 12 years. 5. Component monitoring attributes need to be defined for all components in table 1b and 1c. For example, the attributes for voltage and current sensing devices could be that "Voltage and current input circuits are monitored and alarmed". 6. Based on past performance, the requirement to electrically operate trip coils, auxiliary relays, and lockout relays every 6 years in Table 1b is not warranted. We recommend complete functional testing including electrical operation of breaker trip coils, auxiliary trip relays, and lockout relays every 12 years in tables 1b and 1c.

Response: Thank you for your response.

1. The SDT modified the Table 1b header to address your comment by adding “condition or” to the General Description. See FAQ V-1-D (page 30).

2. The SDT has modified the standard to clarify that this monitoring addresses monitoring of the trip circuit(s), rather than the trip coil(s).

3. The SDT believes that it is important that these mechanical devices be periodically (physically) exercised to assure that they will operate properly.

Organization	Yes or No	Question 4 Comment
4. The SDT believes that the intervals in the table are appropriate. The standard allows entities to utilize Performance-Based maintenance if they have appropriate documented experience. **5. The tables have been modified to address this issue, except where no relevant monitoring attributes exist.** **6. The SDT believes that the intervals in the table are appropriate. The standard allows entities to utilize Performance-Based maintenance if they have appropriate documented experience.**		
US Bureau of Reclamation	No	The condition based monitoring only provides for a very narrow process and excludes sound judgment in determining maintenance intervals. As long as the registered entity establishes parameters by which variation in the prescribed maintenance intervals are determined, justified variation should be allowed.
Response: The SDT thanks you for your comments. The SDT, in accordance with FERC Order 693, has prescribed maximum allowable maintenance intervals for unmonitored Protection System components (Table 1a), partially-monitored Protection System components (Table 1b), and fully-monitored Protection System components (Table 1c). For further discussion pertaining to intervals see Supplementary Reference Document, Section 8 (page 9). To allow an entity to use their discretion to extend these intervals, absent adoption of the criteria established for performance-based maintenance, would be contrary to the direction established by FERC. For further discussion pertaining to performance based maintenance see Supplementary Reference Section 9.		
Austin Energy	Yes	
Bonneville Power Administration	Yes	
CPS Energy	Yes	
Dynegy	Yes	
E.ON U.S.	Yes	
ENOSERV	Yes	
Entergy Services, Inc	Yes	
FirstEnergy	Yes	
Georgia System Operations	Yes	

Organization	Yes or No	Question 4 Comment
Corporation		
Indianapolis Power & Light Co.	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
NextEra Energy Resources	Yes	
Northeast Power Coordinating Council	Yes	
Oncor Electric Delivery	Yes	
Ontario Power Generation	Yes	
Operations and Maintenance	Yes	
Otter Tail Power	Yes	
PacifiCorp	Yes	
Platte River Power Authority Maintenance Group	Yes	
RRI Energy	Yes	
Saskatchewan Power Corporation	Yes	
Transmission Owner	Yes	
TVA	Yes	

Organization	Yes or No	Question 4 Comment
Western Area Power Administration	Yes	
Wisconsin Electric	Yes	
Xcel Energy	Yes	
MRO NERC Standards Review Subcommittee	Yes	A. The MRO NSRS agrees with this approach; however, I think most entities will not see the advantage of condition-based maintenance until they can resolve any gaps in data retention. If an entity was retaining a set of maintenance records but failed to include all the needed information as specified in this standard so they would need to adjust their maintenance procedure to collect all information and then they would need to wait for the entire retention period until they could start using the extended maintenance interval. If an entity had a collateral set of records which verified the information that lacked in the original maintenance record then could the entity start using the extended maintenance interval? For example, an entity has records showing that they have maintained a voltage or current transformer within the prescribed maintenance interval listed in level 1 monitoring (which is a maximum 12 year maintenance interval). Could this same entity go to level 3 monitoring (which is a continuous maintenance interval) immediately if it can query their SCADA and produce detailed records indicating the accuracy of the PT or CT for the maintenance records already retained? B. For lockout relays, if commissioning tests are done diligently, the trip DC availability is continuously monitored and the trip coil itself is continuously monitored, is it necessary to operate these relays for functional testing? For breaker failure lockout relays, re-verifying the operation of the coil and all the contacts could mean taking multiple breakers and line terminals out of service at the same time. Functional trip tests could cause unintentional tripping of equipment, cause equipment damage and interruption of service to customers. It's hard to see how the reliability of the BES is significantly improved by doing this test. The MRO NSRS feels the risk of adverse impact could be greatly reduced by a longer interval such as 12 years. C. In table 1c, the word “continuous or continuously monitored” is used. Please clarify the “within 1 hour” time frame takes into account that there may be a communication outage (failover) that will prevent an entity to “continuously” monitor a device.

Response: The SDT thanks you for your comments.

A. It appears to the SDT that this comment actually is addressing performance-based maintenance, rather than condition-based maintenance. If the entity has all the necessary records to support immediate moving to a specific level of maintenance, or to performance-based maintenance, there should be no barrier to such an action.

B. The SDT is not aware of any monitoring system that can verify that these mechanical devices can indeed physically operate properly; thus the

Organization	Yes or No	Question 4 Comment
interval is established at 6 years. (See Supplementary Reference Document Section 15.4, page 23.) **C. "Continuous monitoring" is an attribute of the Protection System component to produce an indication of state or status; the 1-hour constraint refers to the communication method used to monitor the indications. The equipment used to monitor the alarms must be returned to service within the shortest Table 1a interval of the monitored components. For example, if monitoring is used to defer the 3 month Table 1a maintenance activity related to Protection System Control Circuitry, the monitoring function must be returned to service within 3 months. This has been added to Table 1b and Table 1c as a required attribute for the associated type of protection system component.**		
City Utilities of Springfield, MO	Yes	CU agrees with the approach, but, may not agree with the exact wording in the tables. For instance, the use of the word "every" in table 1c in "Protection System components in which every function required for correct operation of that component is continuously monitored and verified" may be overstating the level of monitoring that would realistically enable a Protection System to use table 1c.
Response: The SDT thanks you for your comments. Table 1c establishes that, with the monitoring attributes specified, periodic maintenance may not be necessary at all. In order to facilitate this, the constraint, "every function required for correct operation of that component is continuously monitored and verified" must be met. If a component cannot meet this constraint, it must be addressed within either Table 1b or Table 1a, as appropriate.		
Florida Municipal Power Agency, and its Member Cities	Yes	FMPA agrees with the approach, but, may not agree with the exact wording in the tables. For instance, the use of the word "every" in table 1c in "Protection System components in which every function required for correct operation of that component is continuously monitored and verified" may be overstating the level of monitoring that would realistically enable a Protection System to use table 1c.
Response: The SDT thanks you for your comments. Table 1c establishes that, with the monitoring attributes specified, periodic maintenance may not be necessary at all. In order to facilitate this, the constraint, "every function required for correct operation of that component is continuously monitored and verified" must be met. If a component cannot meet this constraint, it must be addressed within either Table 1b or Table 1a, as appropriate.		
JEA	Yes	Is it possible that for coil monitored equipment, such as LOR coils, that they were left out, of this Table allowing for a longer maintenance interval. Certainly LOR continuous coil monitoring with alarming to a 24 hour 7 day a week manned location, with emergency dispatch, would allow for a longer maintenance interval for continuously monitored LORs. Suggestion here might be alignment with continuously self-tested, monitored and alarmed microprocessor relays at 12 years.
Response: The SDT thanks you for your comments. Monitoring of the coil of these devices does not assure that the device will mechanically operate properly; thus the interval for verification of proper physical operation is established at 6 years similarly to Table 1a and Table 1b. (See Supplementary		

Organization	Yes or No	Question 4 Comment
Reference Document, Section 15.4, page 23.)		
ITC Holdings	Yes	We agree with the approach. We have several issues with the details of Maintenance Issues, Interval and Monitoring Attributes. See previous comments for Questions 2 and 3.
Response: The SDT thanks you for your comments. See response to your comments in Questions 2 and 3.		
Ameren	Yes	We agree with the condition-based approach. Our comments in 3 above apply to Tables 1b and 1c as well. We note that Table 1b Station dc supply intervals are the same as Table 1a. Why doesn't the monitoring cause 1b intervals to be longer than 1a?
Response: The SDT thanks you for your comments. The standard (specifically Table 1b) has been modified in consideration of your comment.		
Lower Colorado River Authority	Yes	We commend the drafting team for recognizing the advantages of using monitored systems and a condition-based approach. This approach recognizes the benefits of using newer technologies and will give utilities added incentive to update their relay systems.
Response: The SDT thanks you for your support.		
Puget Sound Energy	Yes	

5. Within PRC-005 Attachment A, the draft standard establishes parameters for performance-based maintenance, where the historical performance of the devices is known and analyzed to support adjustment of the maximum intervals. Do you agree with this approach? If not, please explain in the comment area.

Summary Consideration: Many of the respondents agreed with this approach, but comments indicated concern about perceived administrative difficulties in establishing performance-based maintenance programs. The SDT responded to these concerns by noting that associated administrative program development is one of the considerations that an entity must address when contemplating use of such a program.

Organization	Yes or No	Question 5 Comment
Green Country Energy LLC		N/A does not apply
MRO NERC Standards Review Subcommittee	No	A. The MRO NSRS is concerned that this approach could lead to non-compliance if the company follows this process and a Compliance Auditor disagrees with the method that was used. An applicable entity should be protected if they follow the standard appropriately. There should be some assurance of a grace period for mitigation if this selected approach was not accepted. B. Please provide the basis for having at least 60, then taking 30 (50%) for testing/maintenance. This may give an unfair advantage to larger companies rather than being fair across the board. This places an undue burden on smaller companies by having to team up with other asset owners.
Response: The SDT thanks you for your comments. **A. See Attachment A of standard. The entity has three years to get performance to an acceptable level (under 4% countable events) or get on the appropriate time-based interval.** **B. The requirement for having 60 and testing 30 is based on having a statistically significant number of devices. Please see Section 9.1 (page 16) of the Supplementary Reference Document for a discussion of the statistical basis. The standard allows smaller entities to share data in order to support their ability to utilize performance-based maintenance.**		
CenterPoint Energy	No	a. CenterPoint Energy lauds the SDT for recognizing that strict imposition of the maximum interval approach creates problems which the SDT attempts to correct by allowing performance-based adjustments. CenterPoint Energy believes the majority of industry commenters will agree with CenterPoint Energy's assessment that the maximum interval approach is problematic and should be dropped from the proposal. However, if the majority of industry commenters agree with the SDT's approach, then a performance-based option to correct the problems introduced by the maximum interval requirements should remain.

Organization	Yes or No	Question 5 Comment
		b. CenterPoint Energy answered "No" to question 5 because CenterPoint Energy believes the arduous path of creating a new set of problems with a rigid approach (maximum interval requirements) and then introducing a complex set of auditable requirements to provide an option (performance-based maintenance) to mitigate the harm of the rigid approach is ill-advised and fraught with pitfalls. Stated otherwise, using performance-based adjustments to correct inappropriate maximum intervals would not be necessary if the inappropriate maximum intervals were not imposed. CenterPoint Energy believes a better approach is to avoid introducing the new set of problems that then have to be mitigated by not imposing problematic maximum intervals. c. Followed to its logical conclusion, using performance-based adjustments to correct inappropriate maximum intervals is a contorted way of arriving at the philosophy embodied in the current set of standards in which entities determine the maximum intervals appropriate for their circumstances and performance. CenterPoint Energy's concern is that the contortions needed to arrive at the same point, in addition to being unnecessary, will be difficult for most entities to navigate. An entity making a good faith effort to comply with the performance-based adjustments will have to navigate through the complexities and nuances of the approach, as illustrated by the extensive set of documents the SDT has provided in an attempt to explain all the requirements and nuances. As an entity attempts to manage this hurdle, the entity will likely have to deal with the reality that the granularity of performance metrics do not exist in most cases to justify to an auditor the rationale for the adjustments to the inappropriate maximum intervals. For example, CenterPoint Energy has asserted that it has had good battery performance using existing practices. However, the assertion is anecdotal. CenterPoint Energy cannot recall any instances where it had a relay misoperation due to battery failure in over twenty five years. CenterPoint Energy does not attempt to keep performance metrics on events that historically occur less than four times a century and CenterPoint Energy believes most entities will be in the same situation. d. If an entity is somehow able to overcome these hurdles, the entity will almost certainly encounter skepticism for what will be viewed as an exception to the default requirement embodied in the standard. Even if an entity can overcome likely skepticism in an audit, the entity will be in a severely disadvantaged situation if a protection system component for which the maintenance interval has been adjusted, based on the entity's good faith effort and reasoned judgment, nevertheless is a contributing factor in a major reliability event investigation, regardless of whether the maintenance interval adjustment contributed to the failure. No matter what maintenance intervals are used, protection system components could fail. If the maintenance interval has been adjusted and if failure occurs, it will likely be unknown whether the interval adjustment was in fact a contributing factor or whether the failure would have occurred anyway. e. Faced with this dilemma, in addition to all the other hurdles to overcome in attempting to adjust an inappropriate maximum interval, the reality is that most entities will accept the inappropriate maximum interval and over-maintain their protection system components, and introduce a new set of reliability risks from such over-maintenance. For these reasons, CenterPoint Energy advises against creating a new set of problem by imposing rigid maximum intervals and then attempting to correct the problems through a performance-based

Organization	Yes or No	Question 5 Comment
		mechanism that in actual practice would likely be illusory.
Response: The SDT thanks you for your comments. **a. FERC order 693 requires that NERC establish maximum time intervals. The criteria for performance-based maintenance are established for entities that wish to establish other intervals based on concise stated criteria.** **b. FERC order 693 requires that NERC establish maximum time intervals. The SDT believes that the established intervals are appropriate. The criteria for performance-based maintenance are established for entities that wish to establish other intervals based on concise stated criteria.** **c. Entities are not required to use PBM, but instead may elect to simply use the intervals established in Table 1a, Table 1b, and/or Table 1c. However, if an entity keeps the necessary metrics to conform to Attachment 1, it may find opportunities within PBM; however, the SDT has established that maintenance of station batteries must be performed within a time-based maintenance program.** **d. The standard established maximum intervals, minimum maintenance activities, and, for PBM, minimum requirements (and performance). If an entity is concerned about whether these intervals will yield acceptable performance, it may perform more maintenance, more frequently, than established within the standard.** **e. FERC order 693 requires that NERC establish maximum time intervals. The criteria for performance-based maintenance are established for entities that wish to establish other intervals based on concise stated criteria, but entities are not required to use PBM.**		
ITC Holdings	No	Appendix A fixes a 4% level of “countable events”. Is this number the industry average for countable events? Has the industry average actually been determined? The basis for the 4% requirement noted in Paragraph 5 of Appendix A should be included in the reference document. Also a sample calculation for adjusting the interval is needed to clarify the requirement.
Response: The SDT thanks you for your comments. We used failure and calibration data from some of the utilities on the drafting team to determine the 4% level; this value is also determined such that a single countable event on the 30 unit minimum test sample established via the statistical analysis described in Section 9 of the Supplementary Reference Document (page 15) does not exceed the threshold. See FAQ IV-3-D thru IV-3-F (pages 25-26) which discusses types of Misoperations and correcting segment performance.		
American Transmission Company	No	ATC agrees with this approach but is concerned that Attachment A does not contain enough language to support an entity that implements this practice. This attachment needs to clearly state that following your performance-based maintenance practices satisfies an entity’s compliance obligations. Entities should not be subject to non-compliance over disagreements with their performance-based maintenance methodology.
Response: The SDT thanks you for your comments. The SDT believes Attachment A does contain enough language to support PBM, and this language is further supported by technical guidance from Section 9 of the Supplementary Reference Document (page 15). Additionally, R3 of the standard specifically provides that an entity that follows the requirements detailed in Attachment A is indeed in compliance. The SDT will consider any		

Organization	Yes or No	Question 5 Comment
suggested improvements.		
E.ON U.S.	No	E.ON U.S. recommends keeping with time-based intervals (and the improvement thereof) and staying clear of condition-based performance for the generating stations. But that is not meant to preclude other companies from doing condition-based, if they so prefer.
Response: The SDT thanks you for your comments.		
Indianapolis Power & Light Co.	No	Establishing historical performance and keeping the documentation up to date makes this almost useless
Response: The SDT thanks you for your comments. Entities are not required to use PBM.		
Florida Municipal Power Agency, and its Member Cities	No	FMPA believes that the documented process outlined in Attachment A; "Criteria for Performance Based Protection System Maintenance Program" is biased towards larger entities. The requirement that the minimum population of 60 individual components of a particular segment is required to make a component applicable to this program automatically eliminates most of the small or medium sized entities. Further the need to first test a minimum of 30 individual components in any segment reinforces the same size limitation. FMPA suggests that the Performance-Based Protection System Maintenance Program allow for regional shared databases applicable towards meeting the establishment and testing criteria of similar individual components. This practice will allow for the inclusion of entities of all sizes. This will also provide a greater format for the discussion of lessons learned and improvements to the testing database on a regional basis.
Response: The SDT thanks you for your comments. The requirement for having 60 and testing 30 is based on having a statistically significant number of devices. Please see Section 9.1 of the Supplementary Reference Document (page 16) for a discussion of the statistical basis. The standard allows smaller entities to share data in order to support their ability to utilize performance-based maintenance. See footnote 4 of Attachment A.		
Duke Energy	No	For utilities like us with large numbers of relays it's too complicated, which drives us back to Table 1a.
Response: The SDT thanks you for your comments. Entities are not required to use PBM.		
Illinois Municipal Electric Agency	No	IMEA supports comments submitted by Florida Municipal Power Agency that the process outlined in Attachment A is biased towards larger utilities.
Response: The SDT thanks you for your comments. The requirement for having 60 and testing 30 is based on having a statistically significant number of devices. Please see Section 9.1 of the Supplementary Reference Document (page 16) for a discussion of the statistical basis. The standard allows smaller entities to share data in order to support their ability to utilize performance-based maintenance. See footnote 4 of Attachment A.		

Organization	Yes or No	Question 5 Comment
City Utilities of Springfield, MO	No	It appears that Attachment A was written for large utilities. Some allocation needs to be made for utilities with smaller numbers of components.
Response: The SDT thanks you for your comments. The requirement for having 60 and testing 30 is based on having a statistically significant number of devices. Please see Section 9.1 of the Supplementary Reference Document (page 16) for a discussion of the statistical basis. The standard allows smaller entities to share data in order to support their ability to utilize performance-based maintenance. See footnote 4 of Attachment A.		
Saskatchewan Power Corporation	No	Saskatchewan agrees with the approach, but requires clarification in the definition of segment. The definition uses a population of 60 or more individual components but in the establishment of a PSMP, it only asks for a population of 30 or more. Which number will be used to define the segment?
Response: The SDT thanks you for your comments. The requirement is that a minimum population of 60 units be present, and that at least 30 units be tested on time-based maintenance (Table 1a) prior to moving to PBM. A minimum of 30 units tested is also used for ongoing analysis of the PBM performance, as specified in Attachment A. Please see Section 9.1 of the Supplementary Reference Document (page 16) for a discussion of the statistical basis.		
Austin Energy	No	See item # 10 Comments
Response: See item #10 response.		
Wolverine Power Supply Cooperative, Inc.	No	See question 2 response
Response: See question 2 response.		
Northeast Power Coordinating Council	No	The concept is acceptable, but the requirements to follow in Appendix A seem to be a deterrent from attempting to use this process. Is the term “common factors” meant to take into account variables at locations that can affect the components” performance (lightning, water damage, humidity, heat, cold)”
Response: The SDT thanks you for your comments. The SDT has attempted to make Attachment A as straight forward as possible. The term “common factors” does mean common variables that are expected to affect performance of the component such as lightning, water damage, humidity, heat and cold. The term also means common variables such as design, manufacture, performance history, etc that are expected to affect performance of the component.		
US Bureau of Reclamation	No	The parameters established can only be implemented with documentation that defined in the document but is

Organization	Yes or No	Question 5 Comment
		not readily available.
Response: Before utilizing a PBM for their Protection Systems, an entity must develop the supporting documentation via application of a time-based program (using the Table 1a intervals) in accordance with Attachment A.		
CPS Energy	Yes	
Detroit Edison	Yes	
Dynegy	Yes	
Electric Market Policy	Yes	
ENOSERV	Yes	
Entergy Services, Inc	Yes	
Georgia System Operations Corporation	Yes	
Lower Colorado River Authority	Yes	
Manitoba Hydro	Yes	
Nebraska Public Power District	Yes	
NextEra Energy Resources	Yes	
Oncor Electric Delivery	Yes	
Ontario Power Generation	Yes	
Operations and Maintenance	Yes	

Organization	Yes or No	Question 5 Comment
PacifiCorp	Yes	
Pepco Holdings Inc.	Yes	
Platte River Power Authority Maintenance Group	Yes	
RRI Energy	Yes	
SCE&G	Yes	
SERC (PCS)	Yes	
Southern Company	Yes	
Transmission Owner	Yes	
Western Area Power Administration	Yes	
Wisconsin Electric	Yes	
Xcel Energy	Yes	
FirstEnergy	Yes	Although we agree with the parameters of the proposed PBM, we have the following comments: 1. We question the inclusion of Misoperations in countable events as described in footnote 4. Since standard PRC-004 already requires analysis and mitigation of Protection System Misoperations through a Corrective Action Plan, entities should not be required to repeat this analysis and mitigation in PRC-005. We ask that the SDT clarify the requirements to allow a tie between PRC-005 and PRC-004 so as to assure work is not duplicated. 2. We are not receptive to using this methodology to develop intervals due to the detailed tracking and analysis that will be required to establish maximum intervals. The approach may suit other utilities and thus, we are not opposed to the methodology being contained within the standard.

Organization	Yes or No	Question 5 Comment
Response: The SDT thanks you for your comments. **1. PRC-004 should be used to handle reporting of the Misoperation and its corrective action. However, the misoperation should be included as a countable event required for PBM analysis. The documentation of correction of problems per PRC-004 should also suffice to address resolution of the corresponding maintenance-correctable issue for PRC-005.** **2. Entities are not required to use PBM.**		
JEA	Yes	Approach appears to be well explained. Only one are of concern and that would be delaying the advancement of replacement of EM relay systems with microprocessor, if the PBM population were to decrease below the 60, resulting in not meeting the sample minimum population criteria. Falling below this 60 population sample minimum, might result in an immediate compliance violation.
Response: The SDT thanks you for your comments. The standard is not meant to delay replacement of relays. An entity should do an annual analysis of it segment size and countable events. As the segment population approaches 60, the entity should transition back to a time-based program per Table 1a, Table 1b, or 1c, as appropriate, and assure that the remaining components are maintained accordingly.		
Exelon Generation Company, LLC	Yes	None
TVA	Yes	Should allow inclusion of dc systems as well.
Response: The SDT thanks you for your comments. A Station DC supply that does not include batteries may be fit into a PBM. See Section 15 of the Supplementary Reference Document (page 21) (and FAQ IV-3-G, page 26) for a discussion of why station batteries cannot be included in a PBM.		
Ameren	Yes	While we agree with the approach, batteries should be allowed, not excluded.
Response: The SDT thanks you for your comments. See Section 15 of the Supplementary Reference Document (page 21) (and FAQ IV-3-G, page 26) for a discussion of why station batteries cannot be included in a PBM.		
Puget Sound Energy	Yes	

6. **The SDT has provided a "Supplementary Reference Document" to provide supporting discussion for the Requirements within the standard. Do you have any comments on the Supplementary Reference Document? Please explain in the comment area.**

Summary Consideration: In general, respondents expressed appreciation for the additional technical discussion included within this document. The SDT responded to many comments by explaining the relationship between the Standard and the Reference Document. Several respondents suggested that elements of the extensive discussion be contained within the standard itself, which is contrary to the guidance within the paradigm for NERC Standards.

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration		Will this document be a part of the standard? Are its explanations the official interpretation of the standard?
Response: The FAQ and the Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document. In order that these documents are initially posted with PRC-005-2 when approved, they must undergo industry comment and review, and the Standards Committee must be convinced through that process that the documents align with the standard and are relevant to the standard. With future revisions to PRC-005, the FAQ and Supplemental Reference Document will have to undergo SDT review and industry comment to remain posted with the standard, and the Standards Committee will have to remain convinced of their accuracy and relevance.		
American Transmission Company	No	
City Utilities of Springfield, MO	No	
Detroit Edison	No	
Electric Market Policy	No	
ENOSERV	No	

Organization	Yes or No	Question 6 Comment
Florida Municipal Power Agency, and its Member Cities	No	
Georgia System Operations Corporation	No	
Illinois Municipal Electric Agency	No	
Indianapolis Power & Light Co.	No	
JEA	No	
Manitoba Hydro	No	
Nebraska Public Power District	No	
NextEra Energy Resources	No	
Northeast Power Coordinating Council	No	
Operations and Maintenance	No	
Pepco Holdings Inc.	No	
RRI Energy	No	
SCE&G	No	
SERC (PCS)	No	
Transmission Owner	No	
TVA	No	

Organization	Yes or No	Question 6 Comment
Western Area Power Administration	No	
Wolverine Power Supply Cooperative, Inc.	No	
US Bureau of Reclamation	No	The document will require revisions. 1. Performance based maintenance is establishing a strategy to achieve a desired performance. The document limits strategy to statistical analysis of failure rates. 2. The document assumes a modern protection system with a high level of monitoring. Facilities which barely qualify would not have high end monitoring installed. 3. The document also refers to "exercising a circuit breaker through t relay tripping circuits using remote control capabilities via data communication." This repeated several times throughout the document as a means of increasing the TBM. This function, if indeed used, would require maintenance. This function is very dangerous and could introduce a cyber vulnerability.
Response: The SDT thanks you for your comments. **1. As you say, PBM is an option to achieve a desired performance. The result should be a documented acceptable level of performance, and statistical analysis of failure rates is required as a minimum method to achieve this level of performance.** **2. The standard addresses all generations of equipment with varying levels of monitoring capability, and establishes requirements which address the equipment with no monitoring capability, as well as facilitating effective use of monitoring capabilities of the equipment that DOES have those capabilities.** **3. Exercising a circuit breaker through the relay tripping circuits via a remote communication method is an available option to those entities that wish to use it to satisfy maintenance intervals established in the standard, not to increase them; this is presented as an example of how entities may be able to use remotely performed activities to minimize maintenance requiring station visits. If an entity is concerned about risks presented from remote maintenance activities, they are not required to use such methods. Issues relating to cyber security are outside the scope of this Standard.**		
Ontario Power Generation	No	A well prepared and useful document.
Response: The SDT thanks you for your support.		
MRO NERC Standards Review	No	N/A

Organization	Yes or No	Question 6 Comment
Subcommittee		
Exelon Generation Company, LLC	No	None
Entergy Services, Inc	No	1. Regarding Section 2.3, Applicability of New Protection System Maintenance Standards, there needs to be clarification and examples of applicable relaying associated with the language: and that are applied on, or are designed to provide protection for the BES. For example, is the application of reverse power schemes and directional overcurrent schemes considered applicable when considering the impact to the protection of the BES? 2. We agree with the application of the term "calendar" in the PRC-005-2 Protection System Maintenance Supplementary Reference document. There should be enough flexibility in interval assignments to allow for annual maintenance planning, scheduling and implementation.
Response: The SDT thanks you for your comments. **1. Please refer to Clause 4 (Applicability) of the standard itself, and to the FAQ document (FAQ III – 2 – A, page 20), for further information on this. It appears that this comment is focused on generation plants; Clause 4.2.5.1 of the draft standard states, "Protection system components that act to trip the generator either directly or via generator lockout or auxiliary tripping relays." This Applicability clause would have to be applied to the specific instance of concern.** **2. The SDT thanks you for your comments.**		
PacifiCorp	No	Very helpful.
Response: The SDT thanks you for your comments.		
Austin Energy	Yes	
Ameren	Yes	1) We disagree with the page 22 statement that batteries cannot be a unique population segment of a PBM. 2) What role does the Supplement play in Compliance Monitoring and Enforcement?
Response: The SDT thanks you for your comments. **1. Thank you for your comment concerning your disagreement with the standard Drafting Team that batteries cannot be a unique population segment of a PBM. In FAQ IV-3-G (page 26) and the Supplementary Reference Document (See Section 15.4, page 23), the Drafting team states why batteries are excluded from PBM. The Drafting Team still believes, that for the reasons stated in the FAQ, that batteries cannot be a unique population segment of a**		

Organization	Yes or No	Question 6 Comment
PBM. There was much debate on this topic in the standard drafting process. It is well known that like batteries will behave differently for even slight variations of outside influences such as temperature, station load, battery charger action, number of duty cycles and even time spent on inventory shelf before first charge. The manufacturers' literature all state that you must control outside influences to attain a level of satisfactory performance. To prove this level of satisfactory performance (and possibly to help detect poor performance from outside influences) you must conduct certain routine tests. Routine tests are included within the Standard's tables of maintenance activities. **2. The FAQ and the Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document. In order that these documents are initially posted with PRC-005-2 when approved, they must undergo industry comment and review, and the Standards Committee must be convinced through that process that the documents align with the standard and are relevant to the standard. With future revisions to PRC-005, the FAQ and Supplemental Reference Document will have to undergo SDT review and industry comment to remain posted with the standard, and the Standards Committee will have to remain convinced of their accuracy and relevance.**		
FirstEnergy	Yes	1. Sec. 2.3 (pg. 4) This section appears to be discussing the purpose of the standard and not the applicability. We suggest changing the title of Sec. 2.3 to "Purpose of New Protection System Maintenance Standard." Also, in Sec. 2.3 it states: "The applicability language has been changed from the original PRC-005: '... affecting the reliability of the Bulk Electric System (BES) ...' To the present language: '... and that are applied on, or are designed to provide protection for the BES.' However, the posted Draft 1 of PRC-005-2 still has the original Purpose statement. Is the SDT planning to revise the Purpose statement as discussed in Sec. 2.3 of the Ref. document? It appears that this statement is included in the applicability section 4.2.1 but believe it is more appropriate as a general purpose statement applying to the whole standard. 2. Sec. 2.4 (pg. 4) Remove the extra word "that" from the second sentence of this section. 3. In the Supplementary reference, section 15.4 Batteries and DC Supplies, third paragraph, the SDT indicates these tests are recommended in IEEE 450-2002 to ensure that there are no open circuits in the battery string. This is essentially a continuity check of the battery string. In the fourth paragraph, the SDT states that "..."continuity" was introduced into the standard to allow the owner to choose how to verify continuity of a battery set by various methods, and not to limit the owner to the two methods recommended in the IEEE standards." 4. The SDT in Table 1a, the Maintenance Activity "Verify continuity and cell integrity of the entire battery", and in Table 1b, the Maintenance Activity "Verify electrical continuity of the entire battery". Based on the information in the Supplementary reference, the owner has to choose a method to verify continuity and the measurement of specific gravity and cell temperatures could be the selected method, however it should not be a required maintenance activity as shown in Tables 1a and 1b.

Organization	Yes or No	Question 6 Comment
Response: The SDT thanks you for your comments. **1. This clause of the document DOES specifically discuss the Applicability clause of the Standard; PRC-005-2 Section 4.2.1 states "Protection Systems that are applied on, or are designed to provide protection for the BES."** **2. The Supplementary Reference Document has been changed in consideration of your comment – the extra "that" has been removed.** **3. The standard and FAQ (See FAQ II-5-D, page 13) have been modified in consideration of your comments concerning checking continuity using specific gravity.** **4. Table 1a and Table 1b of the draft standard have been modified to remove requirements relating to measurement of cell temperature and specific gravity.**		
CPS Energy	Yes	Adds to the confusion with the standard, FAQ, and Supplemental. The three documents at times describe things a little differently.
Response: The SDT thanks you for your comments and is aligning the associated documents with changes to the standard.		
AEP	Yes	Although helpful in understanding and clarifying intent, the requirements of a standard should be clearly written so that multiple, lengthy supporting documents are not needed. These supporting documents do not get recorded into the registry as part of the standard and may or may not be used by auditors during compliance audits which could lead to different interpretations.
Response: The SDT thanks you for your comments. The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document. In order that these documents are initially posted with PRC-005-2 when approved, they must undergo industry comment and review, and the Standards Committee must be convinced through that process that the documents align with the standard and are relevant to the standard. With future revisions to PRC-005, the FAQ and Supplemental Reference Document will have to undergo SDT review and industry comment to remain posted with the standard, and the Standards Committee will have to remain convinced of their accuracy and relevance.		
CenterPoint Energy	Yes	CenterPoint Energy believes the need for an extensive "Supplementary Reference Document", in addition to 13 pages of tables and an attachment in the standard itself, illustrates that the proposal is too prescriptive and complex for most entities to practically implement. CenterPoint Energy would prefer the SDT leave the existing requirements substantially intact or, if most industry commenters prefer the SDT's approach, that the SDT

Organization	Yes or No	Question 6 Comment
		attempt to simplify it.
Response: The SDT thanks you for your comments. The NERC Standard Development Procedure establishes that the standard prescribe requirements, but avoid "how to" or "why" discussions. The SDT, in accordance with FERC Order 693, has prescribed maximum allowable maintenance intervals for various Protection System Components, has provided opportunities for entities to use advanced technologies to perform physical maintenance less frequently, and to use analytical techniques to customize their intervals. At its simplest, an entity could implement a pure time-based program utilizing Table 1a, and much of the additional explanation in the Supplementary Reference Document would not be needed by that entity.		
Public Service Enterprise Group Companies	Yes	Figure 2 "typical generation system" shows a typical auxiliary medium voltage bus, suggest that a line of distinction (dotted line) be added to the figure that defines the element connected to the BES (station Aux Transformer - SAT) and equipment not associated with protection of the SAT be shown as not part of the BES-PSMP.
Response: The SDT thanks you for your comments. The figures are provided to help describe the components of the Protection System, and are not intended to fully describe the boundaries of the BES, the definition of which may vary by Region.		
Wisconsin Electric	Yes	How much authority or weight will this document have with Compliance staff? If potential violations of the standard requirements are alleged by Compliance staff, can this document be cited by an entity when the document provides clarifying information on the requirements?
Response: The SDT thanks you for your comments. This document is not part of the standard, but is intended to provide the rationale of the SDT, as well as guidance about how the various requirements might be met. The explanations are not an "official" interpretation of the standard, but may be useful to determine how to implement various facets of the standard.		
Green Country Energy LLC	Yes	Huge help to us!
Response: Thank you for your support.		
Platte River Power Authority Maintenance Group	Yes	1. It isn't clear in the Supplementary Reference Document why lock-out relays (86) are included as a component of Protection Systems that require a 6 year maximum interval. Historically we haven't experienced any failures with lock-out relays and feel the risk of causing a system reliability issue by removing it from service and restoring it far outweighs the benefits of testing it. What, if any evidence, i.e. equipment failure, does the standard drafting team use to mandate routine testing of 86 devices? Are we fixing something that isn't broke here? 2. The FERC order directed NERC to submit a modification to PRC-005-1 that includes a requirement that maintenance and testing of a protection system be carried out within a maximum allowable interval that is

Organization	Yes or No	Question 6 Comment
		appropriate to the type of the protection system and its impact on the reliability of the BPS. It would seem more appropriate to allow each entity to set their own maximum allowable interval based on studies and historical data of their specific protection system and impact on the reliability of the BPS opposed to a blanket approach that covers all systems regardless of their size or system configuration.
Response: The SDT thanks you for your comments. **1. There are events in the industry that point to a failure of an electro-mechanical 86 device failing, and these devices are essential to proper functioning of the Protection System. PBM principles can be utilized to extend maintenance intervals. (See Supplementary Reference Document, Section 9, page 15.)** **2. FERC Order 693 directed that NERC establish maximum maintenance intervals, which does not provide the latitude to continue to allow entities to set their own intervals. The SDT has, however, added the ability of an entity to follow PBM principles, as you describe, thus adjusting the time intervals between required hands-on maintenance activity to reflect an entity's experience.**		
Progress Energy	Yes	Progress Energy is concerned that separating this document from the standard may lead to issues down the road. If the desire is to consolidate and clarify existing standards, then the two documents should be merged. Otherwise the reference document may get lost from the standard, or might get changed without due process, or might not even be recognized by FERC.
Response: The SDT thanks you for your comments. The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document. In order that these documents are initially posted with PRC-005-2 when approved, they must undergo industry comment and review, and the Standards Committee must be convinced through that process that the documents align with the standard and are relevant to the standard. With future revisions to PRC-005, the FAQ and Supplemental Reference Document will have to undergo SDT review and industry comment to remain posted with the standard, and the Standards Committee will have to remain convinced of their accuracy and relevance.		
Southern Company	Yes	1.Section 15.3 DC Control Circuitry: Although we agree with the premise that auxiliary trip relays and lock-out relays are similar in nature to EM relays and breakers, we believe that based on past performance, a complete functional test trip every 6 years is not warranted. This complete functional test introduces additional risk to our maintenance program not only from a human error perspective but also from the additional frequency of switching and outages required. Our experience has shown that 12 years is an appropriate maximum time interval (rather than 6 years.) 2. The Protection System Maintenance Supplementary Reference (Draft 1), section 8.4, states that the intervals using the term "calendar" are allowed to be completed by the end of the applicable period, not necessarily

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 6 Comment</th></tr>
<tr><td></td><td></td><td>exactly at the interval specified. The only intervals specified in the PRC-005-2 tables are “calendar years” and “months”. We believe that the “calendar” description should be extended to the “months” designator also to also provide some maintenance flexibility (i.e. if an inspection were performed March 1st and was on a three month interval, it would not be required until the end of June). This section should remove the term “calendar” and use “months” and “years” with an appropriate explanation of the intent of the durations.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments.
1. The SDT believes that the intervals within the standard are appropriate. The standard permits the use of Performance-Based maintenance if an entity has documented experience that supports longer intervals.
2. The standard was modified to append “Calendar” in front of “Months” in the Tables in consideration of your comment.</td></tr>
<tr><td>Dynegy</td><td>Yes</td><td>Suggest including operational verification (i.e. analysis of protection system operation after a system event) as an acceptable method of verification.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments. Verification through analysis of events is an acceptable method of verification. Section 11 of the Supplementary Reference Document (page 18) speaks to this topic.</td></tr>
<tr><td>Oncor Electric Delivery</td><td>Yes</td><td>The “Supplementary Reference Document” provides good technical justification for the various approaches to a maintenance program (Time Based, Performance Based, and Condition Based) or combinations of these programs that an owner of a Protection System can follow.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your support.</td></tr>
<tr><td>Xcel Energy</td><td>Yes</td><td>The information in the supplementary reference document is very helpful and valuable. Yet, it is not clear how the document would be managed/revised, nor what role it plays in compliance monitoring. There needs to be a clear understanding if everything in the document is required for compliance, e.g. criteria for monitored systems, etc.
Additionally, we feel that evidence should be addressed within the supplementary reference document.</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your support. The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document. In order that these documents are initially posted with PRC-005-2 when approved, they must undergo</td></tr>
</table>

Organization	Yes or No	Question 6 Comment
industry comment and review, and the Standards Committee must be convinced through that process that the documents align with the standard and are relevant to the standard. With future revisions to PRC-005, the FAQ and Supplemental Reference Document will have to undergo SDT review and industry comment to remain posted with the standard, and the Standards Committee will have to remain convinced of their accuracy and relevance. The Supplementary Reference Document and FAQ have been updated to include a discussion pertaining to evidence for compliance.		
Saskatchewan Power Corporation	Yes	The supplementary reference document is useful information if properly explained and justified. Are the suggestions in the reference document to become part of the standard, or simply recommendations of best practice from industry and serve as a document to reduce the number of interpretations requested?
Response: The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document. In order that these documents are initially posted with PRC-005-2 when approved, they must undergo industry comment and review, and the Standards Committee must be convinced through that process that the documents align with the standard and are relevant to the standard. With future revisions to PRC-005, the FAQ and Supplemental Reference Document will have to undergo SDT review and industry comment to remain posted with the standard, and the Standards Committee will have to remain convinced of their accuracy and relevance.		
Lower Colorado River Authority	Yes	The Supplementary Reference is well written and helpful in explaining the drafting teams thought process.
Response: The SDT thanks you for your support.		
Duke Energy	Yes	We strongly believe that this document should be made a part of the standard, either as an Attachment or worked into the requirements and tables. This will bring clarity to PRC-005 that is needed to get away from all the past problems that were due to a lack of clarity with the previous PRC-005 standards. Also, all the explanations and guidance lose force if they are not part of the standard. Auditors will only be bound by the standard.
Response: The SDT thanks you for your comments. The NERC Standard Development Procedure establishes that the standard prescribe requirements, but avoid “how to” or “why” discussions. The SDT, in accordance with FERC Order 693, has prescribed maximum allowable maintenance intervals for various Protection System Components, has provided opportunities for entities to use advanced technologies to perform physical maintenance less frequently, and to use analytical techniques to customize their intervals. At its simplest, an entity could implement a pure time-based program utilizing Table 1a, and much of the additional explanation in the Supplementary Reference Document would not be needed by that entity.		

Organization	Yes or No	Question 6 Comment
ITC Holdings	Yes	1. Will clarifications in the Reference Document be enforceable with the standard? 2. For example page 11 of the reference document notes “Voltage & Current Sensing Device circuit input connections to the protection system relays can be verified by comparison of known values of other sources on live circuits or by using test currents and voltages on equipment out of service for maintenance.” Can a maintenance program be confidently established using this or other testing methods included in the reference document? 3. A condensed definition of “Condition Based Maintenance” as described in Section 6 of the Reference document should be included in the standard document itself.
Response: The SDT thanks you for your comments. **1. The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document. In order that these documents are initially posted with PRC-005-2 when approved, they must undergo industry comment and review, and the Standards Committee must be convinced through that process that the documents align with the standard and are relevant to the standard. With future revisions to PRC-005, the FAQ and Supplemental Reference Document will have to undergo SDT review and industry comment to remain posted with the standard, and the Standards Committee will have to remain convinced of their accuracy and relevance.** **2. The NERC Standard Development Procedure establishes that the standard prescribe requirements, but avoid “how to” or “why” discussions.** **3. Condition Based Maintenance is not intended to be a defined term; however, a discussion of the attributes of condition-based maintenance is captured within the header of Table 1b and Table 1c of the Standard.**		
E.ON U.S.	Yes	1. With reference to Section 8.1., under additional notes is the following bullet:5. Aggregated small entities will naturally distribute the testing of the population of UFLS/UVLS systems and large entities will usually maintain a portion of these systems in any given year. Additionally, if relatively small quantities of such systems do not perform properly, it will not affect the integrity of the overall program. This implies that incorrect performance of a “relatively small quantity” of UFLS relays is acceptable but with the understanding that it is not optimal. E.ON U.S. agrees with this statement in principle, in that the UFLS program is spread out across the system, and there is not a one to one performance expectation as there is with a transmission line or generation protection system. This calls into question the required intervals for testing of these types of relays, and the performance expectations in a PBM program. Given the number of relays spread out across the distribution system, the testing requirements of UFLS relays require longer testing intervals than other bulk transmission system

Organization	Yes or No	Question 6 Comment
		components. 2. 8.2 Is this requirement expected to be retroactive? That is, if the previous retention policy was followed to the letter, an entity could be fully in compliance based on the previous standard, but not be in compliance if PRC-005-2 were retroactive. 3. 8.3 And 8.4 This discussion explains how time based maintenance intervals were determined. The conclusion is based upon surveys of SPCTF members and their existing practices, and seemed to arrive at a maintenance interval based upon a simple average weighed by the size of the reporting utility. No consideration appears to have been given to utilities who have successfully operated with longer test and calibration intervals. In section 5 of the Supplementary Reference it is stated that “excessive maintenance can actually decrease the reliability of the component or system.” With that in mind, some of the intervals defined in the table seem too aggressive. 4. With the proposed PRC-005-2, the Drafting Team has effectively shortened the recommendation for UFLS relays from 10 years to 6 years, with reference to the recommendations of the Protection System Maintenance Technical Reference. E.ON U.S. believes that this is inconsistent with previous comments in Section 8.1, bullet 5 of the notes. 5. Consistent with the comments above and based on E ON U.S.’s internal testing, calibration and verification experience, E.ON U.S. recommends maintenance on UFLS relays that comprise a protection scheme distributed over the power system to be no less than 10 years for Level 1 monitoring and no less than 15 years for Level 2 monitoring. For a PBM program, require the number of countable events within a segment to be no more than 10%, not 4% as proposed.

Response: The SDT thanks you for your comments.

1. The SDT believes that the intervals specified in the standard are appropriate.

2. The new standard will be effective according to the dates established within the standard. The Implementation Plan posted with the standard establishes a path for entities to migrate from their current practices and schedules to those imposed in this standard when approved.

3. Entities that have successful experience with equipment at intervals beyond the Standard’s tables can utilize the Standard’s PBM option.

4. The SDT believes that the intervals specified in the standard are appropriate, and disagrees that the intervals are inconsistent with the cited clause of the Supplementary Reference Document.

5. Allowing the countable events to be increased to 10% would clearly allow an entity to increase its time interval between testing if there was a failure of less than 10% of the testing segment. However, SDT contends that would be an unacceptably high rate of mal-performing Protection System components, and would be detrimental to system reliability. The acceptable failure rate needs to balance between a goal of ultimate reliability and what could be reasonably expected of a well-performing component population.

Organization	Yes or No	Question 6 Comment
AECI	No	
Puget Sound Energy	Yes	PSE appreciates this document as it provides a lot of further clarity. However, we wonder how this document might be used during an audit. What is the formal process for the supplementation reference document to be changed? How will entities be notified?
Response: The SDT thanks you for your support. This document is not part of the standard, but is intended to provide the rationale of the SDT, as well as guidance about how the various requirements might be met. The explanations are not an "official" interpretation of the standard, but may be useful to determine how to implement various facets of the standard. The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document. In order that these documents are initially posted with PRC-005-2 when approved, they must undergo industry comment and review, and the Standards Committee must be convinced through that process that the documents align with the standard and are relevant to the standard. With future revisions to PRC-005, the FAQ and Supplemental Reference Document will have to undergo SDT review and industry comment to remain posted with the standard, and the Standards Committee will have to remain convinced of their accuracy and relevance.		

7. The SDT has provided a "Frequently-asked Questions" document to address anticipated questions relative to the standard. Do you have any comments on the FAQ? Please explain in the comment area.

Summary Consideration: In general, respondents expressed appreciation for the additional technical discussion included within this document. The SDT responded to many comments by explaining the relationship between the standard and the FAQ. Several respondents suggested that elements of the extensive discussion be contained within the standard itself, which is contrary to the guidance within the paradigm for NERC Standards. Additionally, many of the comments in Questions 1-5 were addressed by developing additional FAQ content and referring the respondents to the revised FAQ.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 7 Comment</th></tr>
<tr><td>SCE&G</td><td></td><td>1. The FAQ should be expanded to address the issues raised above with verification of trip circuits as to what is an acceptable method meeting the intent of the standard.
2. We also suggest changing "prove" to "verify" on FAQ 3a to be consistent with the wording of the requirement.
3. Also, for a single bus with one set of bus potential transformers, how does one verify proper functioning of the potentials? Is a reasonableness criterion adequate?</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments.
1. The SDT agrees. The FAQ has been modified to address your concerns. (See FAQ II-4-E, page 11.)
2. The SDT agrees. The FAQ has been modified to address your concerns. (See FAQ II-3-A, page 8.)
3. The entity must verify that the protective devices are receiving the expected potential from the potential transformers or equivalent. If the potentials, both magnitude and phase angle, can be determined to be reasonable, that would suffice. (See FAQ II-3-A, page 8.)</td></tr>
<tr><td>Bonneville Power Administration</td><td></td><td>Will this document be a part of the standard? Are its explanations the official interpretation of the standard?</td></tr>
<tr><td colspan="3">Response: The SDT thanks you for your comments.
The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document.</td></tr>
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Organization	Yes or No	Question 7 Comment
City Utilities of Springfield, MO	No	
Dynegy	No	
Electric Market Policy	No	
ENOSERV	No	
Florida Municipal Power Agency, and its Member Cities	No	
Georgia System Operations Corporation	No	
Green Country Energy LLC	No	
Indianapolis Power & Light Co.	No	
Operations and Maintenance	No	
Platte River Power Authority Maintenance Group	No	
TVA	No	
US Bureau of Reclamation	No	
Western Area Power Administration	No	
Wisconsin Electric	No	
Wolverine Power Supply Cooperative, Inc.	No	

Organization	Yes or No	Question 7 Comment
E.ON U.S.	No	E.ON U.S. disagrees with commissioning tests not being considered as a baseline for subsequent maintenance activities. Commissioning tests should be counted as the initial testing in the scheme of a maintenance program
Response: The SDT thanks you for your comments. **As long as the requirements of the standard are met by the commissioning tests, they can "start the clock" for future maintenance testing. The FAQ has been reworded to clarify this point. (The revised FAQ is IV-2-B, page 23.)**		
Ontario Power Generation	No	It was a good idea to prepare such a document.
Response: The SDT thanks you for your support.		
Pepco Holdings Inc.	No	Item 3.B. (Page 6) claims that a small measurable quantity in 3I0 and 3V0 inputs to relays -may- be evidence that the circuit is performing properly. This statement is weak at best, and incorrect at worst. A balanced transmission system may exhibit 3I0 and 3V0 quantities that are not measurable, and those that are measurable cannot be compared to other readings, since CT/PT error often exceeds system imbalance. Since these inputs are verified at commissioning, recommend that maintenance verification require ensuring that phase quantities are as expected and that 3IO and 3VO quantities appear equal to or close to 0.
Response: The SDT thanks you for your comments. **The SDT agrees; See FAQ II-3-B, page 9.**		
Exelon Generation Company, LLC	No	None
MRO NERC Standards Review Subcommittee	No	Overall, the FAQ's are helpful toward understand what the SDT was thinking. Explanations for questions dealing with the maintenance activities (e.g., battery testing) indicate an attempt to line up the requirement with IEEE standards. While it is commendable to attempt alignment reliability standards with other industry standards, it also begs the question of why requirements that are already covered by other standards should be repeated in reliability standards. In addition, if the other standards are changed, then they could become inconsistent with or contradictory to the reliability standard.
Response: The SDT thanks you for your support. The IEEE standards are voluntary standards, and do not establish any requirements, and also are not measurable. PRC-005 standard requirements are loosely aligned with the IEEE standards and any future minor changes to those IEEE standards would not significantly alter the correlation between PRC-005 standard requirements for batteries and the IEEE recommendations.		

Organization	Yes or No	Question 7 Comment
American Transmission Company	No	Overall, the FAQ's are helpful. Explanations for questions dealing with the maintenance activities (e.g., battery testing) indicate an attempt to line up the requirement with IEEE standards. While commendable to attempt alignment with the industry, it is further justification that maintenance activities should not be included in the standard. Over the long term, technology or IEEE standards could change making the compliance standard inconsistent.
Response: The SDT thanks you for your support. The IEEE standards are voluntary standards, and do not establish any requirements, and also are not measurable. PRC-005 standard requirements are loosely aligned with the IEEE standards and any future minor changes to those IEEE standards would not significantly alter the correlation between PRC-005 standard requirements for batteries and the IEEE recommendations.		
PacifiCorp	No	Very helpful.
Response: Thank you for your support.		
Austin Energy	Yes	
Entergy Services, Inc	Yes	
Manitoba Hydro	Yes	
Public Service Enterprise Group Companies	Yes	1) R1 - PRC-005-1 required the protection owner to supply a "basis" for the chosen maintenance intervals. Is it intended that the new standard will no longer require the protection owners to provide a basis for their intervals as long as they meet (or better) the published required intervals? 2) Compliance 1.4 Data Retention Needs more clarity. Some items require 12 years maximum maintenance interval. However, we may perform the same maintenance in 6 years. The requirement for data retention is 2 maintenance intervals. In this example, does this mean 12 years or 24 years? Are we required to maintain records for the maximum maintenance intervals allowed by the standard or only for the two shorter maintenance intervals that we actually use? 3) Compliance will need some guidance on to what is required for "proper documentation". Generally, the relay technicians will scribe the actual test values for a given tests requiring the application of AC voltage and current. However, as an example, when performing DC checks (DC aux relay), the technician may simply state that the aux relay is "OK" without stating the DC coil pickup value in volts. Is this acceptable? Another example may be when performing battery inspections (i.e., verify proper voltage of station battery, verify that no DC grounds exist, etc), the inspector may simply indicate/document that the battery is "Ok". This would indicate that appropriate 3 month inspections (as per table 1a) were completed and found to be within tolerances. Is this acceptable? If

Organization	Yes or No	Question 7 Comment
		specific details are required to be stored on test media (paper test sheets, computer based data storage, etc), then please make some comments as such. 4) Table 1a DC supply. The 3 month inspection requires “verify that no dc supply grounds are present”. This needs further clarification. What is the defined “limit” to determine whether we have a DC ground? The detection methods for determining the presence of a DC ground will vary from indicating light balance to actual DC ammeters or voltmeters. It is assumed that the intent of this requirement is to ensure that there are no full DC grounds (dead shorts) in the DC terminals. Please clarify. 5) In the group by type of BES facility descriptions on pages 15 and 16 there is discussion about generation station auxiliary transformers and associated protection devices. It also cites examples of relays which need not be included even though they could result in tripping of the generating station. The line of demarcation is not well defined in the FAQs or in the standard itself. Suggest that verbiage be added that clearly defines the element (transformer) directly connected to the BES and its associated protection is what is included in the PSMP requirements, items connected at lower voltage (down stream) are not within the PSMP requirement. 6) On page 15, the sample list of what is included in the standard, suggest that the list be expanded to show what is not included (a relay that monitors parameters and is used for control/ alarm but not protection); generator excitation controls that trip an auxiliary exciter. The list of items not included in the PSMP but that could trip the unit should be further defined and expanded.

Response: The SDT thanks you for your comments.

1. The SDT agrees that no basis is required for level 1 monitoring as detailed in Table 1a. Monitoring attributes will be required to meet Table 1b and Table 1c requirements. A performance based program will require further documentation; see Attachment A of the standard.

2. The SDT has modified the Data Retention area of the standard to clarify this.

3. The SDT will consider acceptable forms of evidence when developing the Measures. See the FAQ IV-1-B, page 21. Also, see Section 15.6 (page 24) of the Supplementary Reference Document for a discussion of “evidence”.

4. Table 1a has been modified to address this, and an FAQ (FAQ II-5-I, page 15) has been added to clarify this. The revised language in the standard reads:

> **Check for unintentional grounds.**

5. The SDT agrees; the FAQ has been modified to address your concerns see FAQ III-2-A, page 20.

6. The definition of Protection System states that “Protective relays, associated communication systems necessary for correct operation of protective devices, voltage and current sensing inputs to protective relays, station DC supply, and DC control circuitry from the station DC supply through the trip coil(s) of the circuit breakers or other interrupting devices.” Controls and alarms are excluded per the definition.

Organization	Yes or No	Question 7 Comment
Ameren	Yes	1) We don't think an Executive Summary is needed. 2) Please include the Supplement's explanation of A/D verification method from Supplement page 9. 3) What role does the FAQ play in Compliance Monitoring and Enforcement? 4) Refer to question 2 and add our items # 2, 3, 4, 5, 7, and 11 to FAQ. 5) Please add FAQ that provides the NERC Compliance Registry Criteria for Generating Facilities, to clarify applicability to >20MVA direct BES connection, aggregate >75MVA etc. 6) FAQ 2A p17 states that commissioning is construction, not maintenance. It seems like you're ignoring the significant verification, testing, inspection, and calibration activities that occur in commissioning. Should the in-service date be assigned to these components for determining their next maintenance? 7) Refer to question 3 and add our items # 4 to FAQ.
Response: The SDT thanks you for your comments. **1. The SDT thanks you for your input.** **2. The SDT agrees; this information was already present in FAQ V-3-B (page 38).** **3. The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document.** **4. The SDT agrees; see our response to your comment on Question 2.** **5. The NERC Compliance Registry Criteria and Regional BES definitions are themselves requirements upon entities, and need not be explained within the PRC-005 FAQ.** **6. As long as the requirements of the standard are met by the commissioning tests, they can "start the clock" for future maintenance testing. See FAQ IV-2-B (page 23).** **7. The SDT agrees; see our response to your comment on Question 3.**		
NextEra Energy Resources	Yes	a. NextEra Energy believes the need for an extensive "Supplementary Reference Document", in addition to 13 pages of tables and an attachment in the standard itself, illustrates that the proposal is too prescriptive and complex for most entities to practically implement. NextEra Energy would prefer the SDT leave the existing

Organization	Yes or No	Question 7 Comment
		requirements substantially intact or, if most industry commenters prefer the SDT's approach, that the SDT attempt to simplify it.7. The SDT has provided a "Frequently-asked Questions" document to address anticipated questions relative to the standard. Do you have any comments on the FAQ? Please explain in the comment area. 1 Yes 0 No Comments: a. An alternative to measuring battery specific gravity is to measure float voltage and float current as described in Annex A4 of IEEE Std 450-2002. b. FAQ Page 17 (#1B): It is outside the jurisdiction of the standards development team to determine acceptable forms of evidence. This should be decided by the Regional Entities. c. FAQ Page 15 (#1A): This question should not have been included since it is addressing the definition of BES, which is currently being addressed by another NERC Group. d. FAQ Page 15 (#2): Although the FAQ is not enforceable, the answer provided may be interpreted as enforceable. This should be included in the standard and not in the FAQ.
Response: The SDT thanks you for your comments. **The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. The SDT has therefore defined the minimum activities and maximum intervals necessary to implement an effective PSMP.** **a. The SDT has modified the standard in consideration of your comment by removing the maintenance activity of measuring specific gravity.** **b. Other commenters have requested assistance in determining applicable evidence. The SDT has provided guidance that agrees with entities' experience regarding effective evidence during actual audits. See FAQ IV-1-B, page 21 and Supplementary Reference Document, Section 15.6, page 24.** **c. Including the definition of the BES in the FAQ is helpful to some entities, and addresses common questions from other commenters; the FAQ states that the RRO's may have additional criteria.** **d. The FAQ is intended to present examples of applicable devices, and is not intended to be all-inclusive. The requirements are established by the standard definition of Protection System and the section 4 ("Applicability").**		
CPS Energy	Yes	Adds to the confusion with the standard, FAQ, and Supplemental. The three documents at times describe things a little differently.
Response: The SDT thanks you for your comments, however in the future please be more specific and identify the actual discrepancies so we can		

Organization	Yes or No	Question 7 Comment
improve the documents.		
AEP	Yes	Although helpful in understanding and clarifying intent, the requirements of a standard should be clearly written so that multiple, lengthy supporting documents are not needed. These supporting documents do not get recorded into the registry as part of the standard and may or may not be used by auditors during compliance audits which could lead to different interpretations.
Response: The SDT thanks you for your comments. The SDT believes that providing additional references helps clarify the requirements in the standard. The SDT must address the directives of FERC orders 672 and 693 without being too prescriptive within the standard itself. According to the NERC Standard Development Procedure, a standard is to contain only the prescriptive requirements; supporting discussion is to be in a separate document.		
Transmission Owner	Yes	An alternative to measuring battery specific gravity is to measure float voltage and float current as described in Annex A4 of IEEE Std 450-2002.
Response: The SDT has modified the standard in consideration of your comment by removing the maintenance activity of measuring specific gravity.		
SERC (PCS)	Yes	Change “prove” to “verify” on FAQ 3a (under Voltage and Current Sensing Devise Inputs to Protective Relays) to be consistent with the wording of the requirement.
Response: The SDT thanks you for your comments. See FAQ II-3-A (page 8) – the word, “prove” was replaced with “verify” as proposed.		
Detroit Edison	Yes	Example #1 on page 21 states “A vented lead-acid battery with low voltage alarm connected to SCADA. (level 2)”. However, Table 1b indicates that detection and alarming of dc grounds is also required for level 2.
Response: The SDT thanks you for your comments. The cited example is intended to show a mixture of Level 1 and Level 2 monitored components. Those components not equipped with Level 2 monitoring must be maintained in accordance with Table 1a. Also, see the Decision Tree at the end of the FAQ, addressing DC Supply monitoring levels.		
ITC Holdings	Yes	1. FAQ page 6 question 3C should be clarified in the standard document itself. What is the technical justification for omitting insulation testing of the wiring for DC control, potential and current circuits between the station-yard equipment and the relay schemes? We feel this wiring is susceptible to transients which, over time, may compromise the insulation, and therefore should be tested. 2. FAQ page 17 question 2A the standard should define when the first maintenance activity is to be performed. We include our maintenance activities during commissioning, and set the next maintenance due date based on the testing interval.

Organization	Yes or No	Question 7 Comment
		3. Will clarifications in the FAQs be enforceable with the standard? Can a maintenance program be confidently established using this or other answers included in the FAQ's?
Response: The SDT thanks you for your comments. **1. The SDT does not believe that insulation testing needs to be included within the minimum required maintenance activities; the SDT is not aware of a body of evidence that suggests that these tests should be included as a requirement. The proposed standard does not prevent an entity from including such tests in its program if their experience has indicated that such testing is needed. Furthermore, requirements for checking for proper current and voltage at the relays and checking for DC grounds, provides some assurance of cable insulation integrity.** **2. As long as the requirements of the standard are met by the commissioning tests, they can "start the clock" for future maintenance testing. See FAQ IV-2-B, page 23.** **3. The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority.**		
Nebraska Public Power District	Yes	On page 17, the answers to questions 2B and 2C indicate that there is no allowance or provision to exceed the Maximum Maintenance Interval under any circumstances, except that natural disasters or other events of force majeure will receive special consideration when determining sanctions. The rigidity of this performance requirement could conceivably require equipment to be tested even though it is out of service in order to remain compliant, adding unnecessary cost and waste to the PSMP of the regulated entities. We believe that a prescriptive process for deferring testing and maintenance beyond the stated interval would be beneficial to allow the necessary flexibility to manage the PSMP effectively.
Response: The SDT thanks you for your comments. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue. **Should maintenance be due on equipment that is out-of service for a protracted period, the required maintenance should only be necessary before the equipment is returned to service. However, you may encounter compliance challenges if you did not complete the maintenance during the scheduled period, and should be prepared to document the out-of-service period and the subsequent maintenance.**		
Southern Company	Yes	Part of the responses could be more correctly stated: Page 11E, "why is specific gravity testing required" The specific gravity measurements do not reflect accurate state of charge for lead-calcium batteries. (Float current is

Organization	Yes or No	Question 7 Comment
		a better parameter for this indication)
Response: The SDT thanks you for your comments concerning specific gravity being required. The SDT has modified the standard by removing the requirement for specific gravity testing.		
FirstEnergy	Yes	Pg. 17 (What forms of evidence are acceptable) Although Measures are not yet developed and posted with the standard, we wanted to point out that the SDT should consider adding these acceptable forms of evidence in the measures of the standard.
Response: The SDT thanks you for your comments. The SDT will consider identifying acceptable forms of evidence when developing the Measures.		
Progress Energy	Yes	Progress Energy is unclear how a new/revised standard can have a 30 page FAQ document associated with it. If questions need to be addressed, the answers should be incorporated into the existing standard. During this stage of the draft, all questions should be addressed, not left to the side in an “interpretation” paper.
Response: The SDT thanks you for your comments. The SDT believes that providing additional references helps clarify the requirements in the standard. The SDT must address the directives of FERC orders 672 and 693 without being too prescriptive within the standard itself. According to the NERC Standard Development Procedure, a standard is to contain only the prescriptive requirements; supporting discussion is to be in a separate document.		
RRI Energy	Yes	Reverse power relays do not belong in the list of devices within the scope of this standard; reverse power is not used for generator protection or protection of a BES element. Aside from the protection of reverse power for other non-BES equipment, a generator can operate continuously as a generator, synchronous condenser, or a synchronous motor. Reverse power relays (or reverse power elements in multi-function relays) is commonly used as a control function for automatic shut-down purposes, which is not a protective function. Other reverse power protection, with longer time delays, is provided for turbine protection, which is not within the scope of the NERC Standards.
Response: The SDT thanks you for your comments. For some power plants, the reverse power relays trip the generation output breaker(s) and thus are in scope per section 4.2.5.1 of the standard. The list of devices provides examples which may or may not be in scope of the standard depending upon how they applied.		
CenterPoint Energy	Yes	See CenterPoint Energy’s response to question 6. The need for an FAQ document in addition to an extensive “Supplementary Reference Document” further illustrates the complexity and impracticality of the proposed standard revisions.
Response: The SDT thanks you for your comments. See the response to your comments on Question 6.		

Organization	Yes or No	Question 7 Comment
The SDT believes that providing additional references helps clarify the requirements in the standard. The SDT must address the directives of FERC orders 672 and 693 without being too prescriptive within the standard itself. According to the NERC Standard Development Procedure, a standard is to contain only the prescriptive requirements; supporting discussion is to be in a separate document.		
Oncor Electric Delivery	Yes	The FAQ document is an excellent resource document for Protection System Owners to understand why the maintenance activities listed in the proposed standard were chosen.
Response: The SDT thanks you for your support.		
JEA	Yes	The FAQ is a well written document and the team should take pride in its clarity and informative content. One area that would be good to have further clarification, is if the SDT could provide a current industry product or example of the "software latches or control algorithms, including trip logic processing implemented as programming components, such as a microprocessor relay that takes the place of (conventional) discrete component auxiliary relays or lockout relays that do not have to be routinely tested." Is this a microprocessor lockout relay (that does not require trip testing?)
Response: The SDT thanks you for your support. The description indeed does reflect a microprocessor relay with imbedded lockout relay functions that does not require trip testing for the lockout function. However, the breaker trip coil would still need to be tested as otherwise required in the standard. Because of the NERC Antitrust Policy, the SDT is unable to provide commercial examples.		
Northeast Power Coordinating Council	Yes	The FAQ is helpful in answering many of the obvious questions.
Response: The SDT thanks you for your support.		
Saskatchewan Power Corporation	Yes	The FAQ section is beneficial, but would suggest reviewing it to determine if it can be integrated within the reference document.
Response: The SDT thanks you for your support. The SDT will, to the degree possible, integrate material from the FAQ into the Supplementary Reference Document. The SDT additionally believes that there is value in the FAQ that presents the material as questions and answers.		
Lower Colorado River Authority	Yes	The Frequently-asked Questions document is very well written and very helpful. The decision trees are a good addition.
Response: The SDT thanks you for your support.		

Organization	Yes or No	Question 7 Comment
Xcel Energy	Yes	1. The Frequently-asked Questions seem to act as interpretations to the standard. What roll will they play in determining compliance? 2. On table 1b (page 11) the UFLS and UVLS maintenance activities indicate that tripping of the interrupting device is not required, but it uses the term “functional trip test”. The FAQ indicates that a “functional trip test” does require tripping the interrupting device. This conflicts with what is in the table and should be corrected in the FAQ to reflect that no trip is required.
Response: The SDT thanks you for your comments. **1. The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document.** **2. The SDT agrees with your comment. See FAQ II-4-E, page 11.**		
Illinois Municipal Electric Agency	Yes	Under “Group by Type of BES Facility”, 1. (page 15) “The radial exemption in the BES definition should be clarified to include transmission subsystems within a single municipality, where the transmission facilities serving only subsystem load with one transmission source - essentially operate radially. A more practical application of the radial exemption would address smaller TOs whose system has minimal potential to impact the BES as a whole.
Response: The SDT thanks you for your comments. The BES is a NERC and Regional defined term, and is outside the scope of this drafting team. Requests for clarification regarding the BES definition should be referred to your Regional Entity. It isn’t clear to the SDT whether the example you request is appropriate or accurate.		
Duke Energy	Yes	We strongly believe that this document should be made a part of the standard, either as an Attachment or worked into the requirements and tables. This will bring clarity to PRC-005 that is needed to get away from all the past problems that were due to a lack of clarity with the previous PRC-005 standards. Also, all the explanations and guidance lose force if they are not part of the standard. Auditors will only be bound by the standard.
Response: The SDT thanks you for your comments. The SDT must address the directives of FERC orders 672 and 693 without being too prescriptive within the standard itself. The SDT feels that providing additional references helps clarify the requirements in the standard and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. According to the NERC Standard Development Procedure, a standard is to contain only the prescriptive requirements; supporting discussion is to be in a separate		

Organization	Yes or No	Question 7 Comment
document.		
AECI	Yes	**Group by Type of Maintenance Program:** **2. Time-Based Protection System Maintenance (TBM) Programs** **A. What does this Maintenance standard say about commissioning?** Commissioning tests are regarded as a construction activity, not a maintenance activity. **COMMENT 1:** If we understand the question and answer correctly, we disagree. We believe that the standard should accept commissioning as the first date for the maintenance testing if the commissioning tests correspond to the Standard's TBM testing procedures. Otherwise, maintenance tests on a new substation will be required to be completed (again) based on the Implementation Plan guidelines for PRC-005-02. **Group by Type of Maintenance Program:** **2. Time-Based Protection System Maintenance (TBM) Programs** **C. If I am unable to complete the maintenance as required due to a major natural disaster (hurricane, earthquake, etc.), how will this affect my compliance with this standard.** The NERC Sanction Guidelines provide that the Compliance Monitor will consider extenuating circumstances when considering any sanctions. **COMMENT 2:** We feel that guidelines should be provided for "extenuating circumstances", specifically addressing natural disasters.
Response: The SDT thanks you for your comments. **The FAQ will be reworded to clarify that commission tests can be used to establish initial performance of maintenance as long as the requirements Tables 1a, 1b, & 1c are fulfilled. See FAQ IV-2-B, page 23.** **The SDT believes that "extenuating circumstances" are addressed by the NERC Sanction Guidelines, and are therefore a discretionary issue between the entity and the Compliance Enforcement Authority. Because of the variability in natural disasters and their potential impact on Protection System maintenance programs, it does not seem practical to develop measurable requirements addressing this issue in the context of this standard. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 (page 9) of the Supplementary Reference Document for a discussion on this issue.**		
Puget Sound Energy	Yes	PSE appreciates this document as it provides a lot of further clarity. PSE hopes this document will be updated through by comments and questions provided during the development process. We wonder how this document might be used in an audit as well. What is the formal process for the supplementation reference document to be

Organization	Yes or No	Question 7 Comment
		changed? How will entities be notified?

Response: Thank you for your support.

The FAQ and Supplementary Reference Document are provided as references to present detailed discussions about determination of maintenance intervals and other useful information regarding establishment of a maintenance program, and do not have statutory effect. The SDT believes that these documents provide potentially useful information to the entity in developing and sustaining an effective PRC-005 program, and hopes that these documents will be useful to the entity in establishing support of their program when it is reviewed by the Compliance Enforcement Authority. It is the drafting team's intent that these documents be posted with the standard when approved similarly to the CIP FAQ and the PRC-023 reference document. In order that these documents are initially posted with PRC-005-2 when approved, they must undergo industry comment and review, and the Standards Committee must be convinced through that process that the documents align with the standard and are relevant to the standard. With future revisions to PRC-005, the FAQ and Supplemental Reference Document will have to undergo SDT review and industry comment to remain posted with the standard, and the Standards Committee will have to remain convinced of their accuracy and relevance.

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

Summary Consideration: Most respondents were unaware of any conflicts. Some felt that conflicts existed with existing business or Regional practices, or with other organizations such as the Nuclear Regulatory Commission. The SDT provided clarifying explanations to illustrate that conflicts are not actually present.

Organization	Question 8 Comment
ITC Holdings	Comments: We are not aware of any conflicts.
Response: The SDT thanks you for your comments.	
MRO NERC Standards Review Subcommittee	Conflict: Order 672 says that standards should be clear and unambiguous.
Response: The SDT thanks you for your comments. The SDT must address the directives of FERC orders 672 and 693 without being too prescriptive within the standard itself. The SDT believes that providing additional references helps clarify the requirements in the standard. Also, the SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general.	
Lower Colorado River Authority	Conflict: Potential conflict with PRC-023 as to which PRS systems are applicable per this standard. Comments: PRC-005-2 requires compliance for this standard for all non-radial systems over 100 kV; while, PRC-023-1 prescribes it as below: 1. Title: Transmission Relay Loadability2. Number: PRC-023-13. Purpose: Protective relay settings shall not limit transmission loadability; not interfere with system operators' ability to take remedial action to protect system reliability and; be set to reliably detect all fault conditions and protect the electrical network from these faults.4. Applicability: 4.1. Transmission Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined below:4.1.1 Transmission lines operated at 200 kV and above.4.1.2 Transmission lines operated at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.4.1.3 Transformers with low voltage terminals connected at 200 kV and above.4.1.4 Transformers with low voltage terminals connected at 100 kV to 200 kV as designated by the Planning Coordinator as critical to the reliability of the Bulk Electric System.4.2. Generator Owners with load-responsive phase protection systems as described in Attachment A, applied to facilities defined in 4.1.1 through 4.1.4.4.3. Distribution Providers with load-responsive phase protection systems as described in Attachment A, applied according to facilities defined in 4.1.1 through 4.1.4., provided that those facilities have bi-directional flow capabilities.4.4. Planning Coordinators. We believe Bulk Electric System (BES) owners resources would be better utilized by focusing on relay systems as defined in

Organization	Question 8 Comment
	the above PRC-023-1 and this would still provide high level of reliability for the BES, since not all facilities operating between 100 200KV are critical to the BES. This would not preclude any utilities from applying this standard to other facilities operating at the lower voltage range. Why did the drafting team not use the application language sited in the “Protection System Maintenance - A NERC Technical Reference” which is similar to what is described above from PRC-023-1?
Response: The SDT thanks you for your comments. The Energy Policy Act of 2005, as well as various FERC orders and the NERC Standards Development Process requires that reliability standards should be applicable to the BES (or, in the case of the Energy Policy Act, the BPS, which is almost synonymous). In the case of PRC-023-1, cited in the comment, that SDT as well as the NERC Staff was required to carefully explain why this standard was not specifically applicable to the BES, but instead to a subset of the BES. The 2007-17 SDT has determined that a similar rationale cannot be effectively determined for PRC-005-2, and thus specified that it should be applicable to the BES. It is noted that this applicability is similar to the applicability for PRC-005-1.	
Exelon Generation Company, LLC	Conflict 1. Nuclear generators are licensed to operate and regulated by the Nuclear Regulatory Commission (NRC). Each licensee operates in accordance with plant specific Technical Specifications (TSs) issued by the NRC. TS allow for a 25% grace period may be applied to TS Surveillance Requirements (SRs). Referencing NRC issued NUREGs for Standard Issued Technical Specifications (NUREG-143 through NUREG-1434) Section 3.0, "Surveillance Requirement (SR) Applicability, SR 3.02 states the following:" The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met." 2. Battery Charger Testing 2a. All conditions (grounds, voltages etc) should be compared to "acceptable limits" as specified in nuclear station design basis documents, industry standards or vendor data. 2b. IEEE 450 does not use the word "proper" as utilized in Table 1a (e.g., "record voltage of each cell v/s verify proper voltage of each individual cell.") 3. The NRC Maintenance Rule (10 CFR 50.65) requires monitoring the effectiveness of maintenance to ensure reliable operation of equipment within the scope of the Rule. Adjustments are made to the PM (preventative maintenance) program based on equipment performance. The Maintenance Rule program should provide an acceptable level of reliability and availability for equipment within its scope. Comments: 4. All maintenance activities should include a "grace" period to allow for changes to a nuclear generator's refueling schedule and emergent conditions that would prevent the safe isolation of equipment and/or testing of function. "Grace" periods align with currently implemented nuclear generator's maintenance and testing programs.

Organization	Question 8 Comment
	5. The 3-month maximum interval should be extended to include a grace period to ensure that a 25% grace period is included to align with current nuclear templates that implement NRC TS SRs are documented in the response to Question 8.

Response: The SDT thanks you for your comments.

1. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue.

2a. The SDT agrees that each entity establishes its own "acceptable limits". In this case, "acceptable limits" would seem to be determined in the materials cited, and would apply for PRC-005-2.

2b. The SDT agrees. The SDT modified the standard to address your concerns. The revised maintenance activity now reads: Inspect cell condition of individual battery cells where cells are visible, or measure battery cell/unit internal ohmic values where cells are not visible.

3. The entity must satisfy all applicable requirements (in this case, NERC PRC-005-2 and the NRC 10 CFR 50.65) as they apply to common equipment. Since the NRC requires monitoring of the effectiveness of the program, you must do so even if this isn't in the NERC standard.

4. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue.

5. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 (page 9) of the Supplementary Reference Document for a

Organization	Question 8 Comment
discussion on this issue.	
City Utilities of Springfield, MO	CU is unaware of any conflicts.
Response: The SDT thanks you for your comments.	
Florida Municipal Power Agency, and its Member Cities	FMPA is not aware of any conflicts
Response: The SDT thanks you for your comments.	
Green Country Energy LLC	It would be beneficial to include some administrative (man hour) and cost estimates to comply with this and any future proposed standards so if major budget impacts could be addressed.
Response: The SDT thanks you for your comments. The SDT is unable to assess the costs of any specific entity to comply with this standard, as the SDT is not aware of the degree to which that entity's current program would satisfy the requirements of this standard. Additionally, "man-hours" would vary widely with the size of the entity.	
Operations and Maintenance	No conflicts known.
AEP	No known conflicts.
Duke Energy	None
Electric Market Policy	None
Nebraska Public Power District	None
PacifiCorp	None known.
SERC (PCS)	None known.
Ontario Power Generation	Not aware of any
Georgia System Operations	Not aware of any.

Organization	Question 8 Comment
Corporation	
American Transmission Company	Order 672 says that standards should be clear and unambiguous. This proposed standard is very complex. While the standard allows entities to select the appropriate maintenance strategy (time based, performance based or conditioned based) for their system the amount of data and tracking required to demonstrate compliance will be overwhelming.
Response: The SDT thanks you for your comments. At its simplest, using time-based maintenance and Table 1a, the documentation requirements should not be vastly different than those to prove compliance to PRC-005-1 for a strong compliance program. If more advanced strategies are used, documentation requirements to demonstrate compliance may very well increase. **The SDT believes that it has clearly and unambiguously defined the minimum activities and maximum intervals necessary to implement an effective PSMP, and presented advanced strategies for those entities who wish to utilize them.**	
Indianapolis Power & Light Co.	Performing some of the maintenance activities may cause conflict with regional ISOs and their safe operation of the BES
Response: The SDT thanks you for your comments. To minimize system impact of such maintenance, the maintenance necessarily should be scheduled at a time that minimizes the risks.	
Northeast Power Coordinating Council	Yes--NPCC Directory #3, NPCC Key Facility Maintenance Tables. All areas must implement changes at the same time.
Response: The SDT thanks you for your comments. PRC-005-2 is a NERC standard and as such it will have its own implementation plan. PRC-005-2 when implemented will be an ERO-wide standard which establishes minimum requirements; to the degree that these requirements are more stringent than those currently imposed by any individual Regional Entity, the NERC requirements will govern. Any individual Regional Entity can establish MORE stringent requirements.	
Puget Sound Energy	PRC-STD-005 PRC-005-2 requires a Protection System Maintenance Program (PSMP) while PRC-STD-005 requires a Transmission Maintenance and Inspection Plan (TMIP). Historically the requirements of PRC-005-1 and PRC-STD-005 folded nicely into one consistent plan. Could the maximum intervals identified in PRC-005-2 be expected or audited against under PRC-STD-005 where it does not indicated that much specificity? PRC-STD-005 requires maintenance of lines and breakers over and above what PRC-005-2 the expectations relative to breakers should align.
Response: The SDT thanks you for your comments. An entity can be audited to both NERC Reliability Standards and to Regional Standards, provided that both are mandatory and enforceable. Where applicable, Regional Standards will have more stringent requirements. As for intervals, where different intervals apply to the same piece of equipment, the more stringent intervals apply. Also, the NERC intervals would apply only to the equipment	

Organization	Question 8 Comment
associated with those intervals within the NERC Standard. If the Regional requirements address equipment not addressed within the NERC Standard, only the Regional requirements are relevant.	

9. If you are aware of the need for a regional variance or business practice that we should consider with this project, please identify it here.

Summary Consideration: A number of respondents suggested that the standard should allow "grace periods" to defer maintenance because of a variety of expected difficulties in completing the required activities within the established intervals. The SDT consistently responded that a "grace period" would be contrary to a measurable standard, and that entities should manage their programs to assure that the required activities are completed on schedule.

Organization	Regional Variance or Business Practice	Question 9 Comment
TVA	Business Practice	Allow for deferrals to coordinate with generator outages.
Response: The SDT thanks you for your comments. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue.		
Exelon Generation Company, LLC	Business Practice	Business Practice: Nuclear Electric Insurance Limited (NEIL) variance allowance.
Response: The SDT thanks you for your comments. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue.		
ITC Holdings		Comment: We are not aware of any regional variance or business practice that should be considered

Organization	Regional Variance or Business Practice	Question 9 Comment
		with this project.
Response: The SDT thanks you for your comment.		
Green Country Energy LLC	Business Practice	Contractual commitments existing prior to NERC stds make it difficult to comply with some of the maintenance activities.
Response: The SDT thanks you for your comment. Existing contracts may need to be adjusted to accommodate compliance to NERC standards.		
City Utilities of Springfield, MO		CU is not aware of a need for a regional variance.
Response: The SDT thanks you for your comment.		
Florida Municipal Power Agency, and its Member Cities		FMPA is not aware of a need for a regional variance
Response: The SDT thanks you for your comment.		
Electric Market Policy	Regional Variance	1. It is our understanding that once Project 2009-17: "Interpretation of PRC-004-1 and PRC-005-1 for Y-W Electric and Tri-State" is approved, that the definition of a "Transmission Protection System" would be included within PRC-005-2 or included within the NERC Glossary of Terms. However, the specific protection that would be considered part of the "Transmission Protection System" would also depend on the regional definition of the BES. 2. We suggest that the regions develop a supplement that provides further clarification on what constitutes a "Transmission Protection System" given the regional definition of the BES.
Response: The SDT thanks you for your comments. **1. The 2009-17 interpretation addresses PRC-005-1. The SDT will monitor this interpretation to determine if any changes need to be made to PRC-005-2 in response to this interpretation. In general, a definition cannot be established via the Interpretation process, but only through the comprehensive Standards Development process.** **2. You should present this concern to your region.**		
SERC (PCS)	Regional Variance	1, It is our understanding that once Project 2009-17: "Interpretation of PRC-004-1 and PRC-005-1 for

Organization	Regional Variance or Business Practice	Question 9 Comment
		Y-W Electric and Tri-State" is approved, that the definition of a "Transmission Protection System" would be included within PRC-005-2 or included within the NERC Glossary of Terms. However, the specific protection that would be considered part of the "Transmission Protection System" would also depend on the regional definition of the BES. 2. We suggest that the regions develop a supplement that provides further clarification on what constitutes a "Transmission Protection System" given the regional definition of the BES.
Response: The SDT thanks you for your comments. 1. The 2009-17 interpretation addresses PRC-005-1. The SDT will monitor this interpretation to determine if any changes need to be made to PRC-005-2 in response to this interpretation. In general, a definition cannot be established via the Interpretation process, but only through the comprehensive Standards Development process. 2. You should present this concern to your region.		
American Transmission Company	Business Practice	Jointly-owned facilities should be a component of this standard. Comments: ATC shares services at Substations; consider dividing the services, i.e. batteries and PTs.
Response: The SDT thanks you for your comments. This is a registration issue and it's not within the scope of the SDT. If a company owns a facility that meets the applicability section as described in this standard then it is responsible for the maintenance activities as described in this standard.		
Ontario Power Generation	Regional Variance	Maintenance activities, and especially intervals, prescribed in NPCC Directory 3 (Maintenance Criteria for BPS Protection) often differ from those in PRC 005 - 02. We recommend that NPCC aligns Directory #3 with PRC 005 - 02 as much as possible. Technical justification should be provided for any variance.
Response: The SDT thanks you for your comments. Any Regional Entity may develop its own requirements, as long as they are not less stringent than the NERC requirements. The SDT suggests that the commenter communicate with the NPCC regional staff regarding this concern.		
AEP		No none regional or business practice variances known.
Nebraska Public Power District		None
PacifiCorp		None known.

Organization	Regional Variance or Business Practice	Question 9 Comment
Georgia System Operations Corporation		None.
Operations and Maintenance		None.
Northeast Power Coordinating Council		Not aware of any regional variance or business practice.
Response: The SDT thanks you for your comment.		
JEA	Regional Variance	Regional variances in the Bulk Electric System definition as applied across regions allows for PSMP to vary possibly even for the same region crossing tie lines. Also, accepted maintenance practices by one region vary from accepted maintenance practices from another region. In the case of lower kV non-redundant bus lockout protection systems, one region may allow for the protection system to be taken out of service to perform maintenance, while another region may specifically prohibit this practice (don't leave energized equipment protected by delayed clearing, etc.)
Response: The SDT thanks you for your comment.		
Duke Energy	Regional Variance	Regions with ISO's and RTO's - Where the independent system operator (ISO) is not the same company as the entity doing testing and maintenance, the independent system operator could prevent the entity from performing scheduled maintenance and testing due to outage request constraints. There should be no violation in such a situation, and the maintenance and testing just rescheduled.
Response: The SDT thanks you for your comments. **The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 (page 9) of the Supplementary Reference Document for a discussion on this issue.**		
Wisconsin Electric	Regional Variance	See above Question 2, Item 7: There needs to be some recognition that Protection System's applied on distribution-voltage systems may be included in a regional definition of a BES Protection System. These systems are not designed or operated in the same way as Transmission or Generation

Organization	Regional Variance or Business Practice	Question 9 Comment
		Protection Systems. Therefore, it is reasonable that these systems be subject to less rigorous requirements.
Response: The SDT thanks you for your comments. See our response above to Question #2, item 7.		

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

Summary Consideration: This question generated numerous comments and many respondents repeated comments offered earlier in the document. Several of the respondents objected to the establishment of maximum allowable intervals at all, and suggested that it should be left to the entities to establish their own intervals; the SDT explained that this would be directly contrary to FERC directives related to the four current standards which are being addressed within this project. Additional technical comments covered the full spectrum of the material in the standard and associated reference documents, and resulted in extensive changes to the standard and in changes to both the Supplementary Reference (mostly to correct inconsistencies) and to the FAQ (including addition of many additional topics). There was also concern about the documentation necessary to demonstrate compliance.

Organization	Question 10 Comment
Ameren	1) Documentation could be a monumental task. Although FAQ 1B allows a comprehensive set of forms of documentation, a very large number of people are involved across this set at most utilities. Producing a particular needle in the haystack may take longer than an auditor would expect. Inspection forms can be structured to capture abnormal conditions, and thus normal conditions are not recorded. Some items, like the red light monitoring a trip coil, may only be reported by exception (i.e., “red light out, replaced bulb” but if the red light is on an operator may not report that). 2) We presume that the SDT would expect transmission facilities to be switched out of service if maintenance would result in those facilities being unprotected. We think this should be stated or clarified, as there may be entities that still use differential cutoff switches or other means of disabling protection for testing and have not considered the consequences of a concurrent fault.
Response: The SDT thanks you for your comments. **1. Much of your concern can be addressed within your program by careful design of your maintenance tracking forms and systems. In your example of a red light, your maintenance can include documentation forms that require completion of either of multiple choices (e.g., OK, Not OK with resolution, etc).** **2. This consideration relates to general planning, design, and operational issues, and is outside the scope of this standard. Various other NERC standards apply.**	
Public Service Enterprise Group Companies	1) R4 requires all maintenance correctable issues identified as part of a time based maintenance plan to be resolved in that same maintenance period. This places a burden on some items (for example, 3 month battery inspections) to achieve adequate resolution for problems that are not an immediate threat. For example, if a battery with a somewhat out of allowable range specific gravity is found near the end of the maintenance period, scheduling and performing the work to replace the battery could reasonably extend somewhat beyond the end of maintenance period. PSE&G requests that the drafting team revisit this

Organization	Question 10 Comment
	requirement and allow flexibility for corrections to be made within a specified reasonable timeframe when correctible issues are identified that for practical reasons require extension for work completion beyond the end of the current maintenance interval. 2) Section 4.2.5.5 of the standard should define provide an example that just the transformer connected to the BES is included and specifically exclude connected equipment beyond the LV terminals. 3) Draft implementation plan for requirements R2, R3 & R4 discusses table 1a as basis, should also address tables 1b and 1c.
Response: The SDT thanks you for your comments. **1. Requirement R4, Part4.3 has been added to the standard in consideration of your comments. It reads as follows:** R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement its PSMP, including identification of the resolution of all maintenance correctable issues[2] as follows: *[Violation Risk Factor: Medium] [Time Horizon: Long Term Planning]* 4.3 Assure either that the components are within acceptable parameters at the conclusion of the maintenance activities or initiate any necessary activities to correct unresolved maintenance correctable issues[3]. **2. The SDT disagrees with your comment. For example, current transformers on low-voltage transformer bushings or low-voltage breakers, which are associated with differential relays, must be considered within application of PRC-005-2. See Figure 2 in the Supplemental Reference Document (page 28) for an illustration.** **3. The SDT believes that the implementation period for PRC-005-2 must be kept as brief as possible; until PRC-005-2 is fully implemented, entities will have to be compliant with PRC-005-2 for those components for which implementation has been completed, and with PRC-005-1 for all other components. However, entities may need considerable time to become compliant with the more specific requirements of PRC-005-2. An implementation period based on Table 1a seems to be the best compromise period to achieve this. Additionally, the Implementation Plan does not require that entities adopt the Table 1a activities and intervals, but instead just refers to the Table 1a components and their intervals for establishment of a phased implementation.**	
Wisconsin Electric	1. In the definition of a Protection System Maintenance Program, the statement is made that "A maintenance program CAN include...” with a list of seven attributes following. Is it the intent that the PSMP "SHALL include one or more of the following”? What is to prevent Compliance staff from concluding that all seven of these attributes MUST be included in the PSMP? 2. The standard should more clearly describe what is meant by "verify..." when used in a Maintenance Activity description. Does

[2] A maintenance correctable issue is a failure of a device to operate within design parameters that can not be restored to functional order by repair or calibration while performing the initial on-site maintenance activity, and that requires follow-up corrective action

[3] A maintenance correctable issue is a failure of a device to operate within design parameters that can not be restored to functional order by repair or calibration while performing the initial on-site maintenance activity and that requires follow-up corrective action.

<table>
<tr><th>Organization</th><th>Question 10 Comment</th></tr>
<tr><td></td><td>this require actual paper or electronic documentation? If so, then this should be explicitly stated in the Maintenance Activity description. We maintain above that the recurring and routine maintenance activities having a 3 month interval should be revised to use alternate words such as "Check" or "Observe". For example, "Check the continuity of the breaker trip circuit...", or "Observe the voltage of the station battery". This activity should not be required to have paper or electronic documentation or evidence. It should be sufficient to have these activities included in the PSMP.

3. It is stated in the Supplementary Reference that actual event data from fault records may be used to satisfy certain Maintenance Activities, yet the standard itself does not appear to allow for this. Will such evidence be accepted by Compliance staff?</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments.

1. Yes, a PSMP should include one or more of the listed activities for any specific component. The definition is intended to identify the possible attributes of a PSMP. Only those attributes relevant to a specific program and component need be included in the PSMP for that component. The proposed definition includes the following phrase, making it clear that the PSMP does not have to include all listed items, “A maintenance program for a specific component includes one or more of the following activities:”

2. The SDT thanks you for your comments and has modified the standard in consideration of your comments.

3. It is difficult to predict what will be accepted by Compliance staff; the SDT believes that you will need to establish a method to capture the evidentiary data from fault records (such as what is empirically verified, when, and how) within your maintenance records. See FAQ IV-1-B (page 21), FAQ II-3-B (page 9) and Section 11 (page 18) of the Supplemental Reference Document.</td></tr>
<tr><td>Bonneville Power Administration</td><td>1. Tables 1a, 1b, and 1c were cumbersome to use because we found ourselves flipping back and forth to compare the requirements for the different levels of monitoring. Also, in some cases, the types of components were slightly different between the tables, which created confusion. We believe that it would be much easier to decipher a single table that listed each type of component only once and showed the requirements and maintenance intervals for the different levels of monitoring on a single page. Even if it took an entire page for each component, it would be very useful to see all of the options for that component without having to flip back and forth between tables.

2. Please clarify the requirements for trip coils. Table 1a has as a component type "breaker trip coil only", with a maximum maintenance interval of 3 months, while Table 1b has as a component type "trip coils and auxiliary relays". Table 1b say that there are no monitoring attributes for this component and to use the level 1 intervals, but then gives a maximum maintenance interval of 6 years, which doesn't agree with the 3 month interval given in Table 1a.

3. The terminology used to describe the secondary currents and voltages provided to the relay is confusing. Under the modified definition of a protection system, it includes the term "voltage and current sensing inputs to protective relays", and in the tables it uses the term "current and voltage circuit inputs". These terms, especially the use of the word input, give the impression that the actual input circuitry of the protective relay is what is being described, but we believe that these terms are really meant to describe the secondary currents and voltages from the instrument transformers (or other devices). BPA suggests revising the terminology</td></tr>
</table>

Organization	Question 10 Comment
	to describe the secondary currents and voltages. For example, in the maintenance activities section of the tables, you could say, "Verify that the secondary current and voltages provided to the relay are correct". 4. There is no mention to what the thresholds are when performing these maintenance activities or what corrective actions must take place and by when they need to be carried out. Is this something we should expect to see soon? 5. The need to measure the cell/unit internal ohmic value every 18 months can be argued. BPA's Substation Maintenance crew performs these measurements once every 24 months and with the Operators monthly inspections, we have been able to effectively catch any problems before a severe event/failure. 6. Communications: It is not clear specifically what equipment is included in "communications". The test interval of 12 years in table 1b is too long to verify continued proper operation of transfer trip tone equipment. Monitoring the presence of the channel does not provide any indication of whether the equipment can initiate a trip. Consequently, a required minimum interval of 12 calendar years is too long and does not do anything to verify proper communications support of the relay scheme. A shorter interval of 6 years, such as that in table 1a makes more sense from a functionality standpoint.
Response: The SDT thanks you for your comments. **1. The SDT has experimented with various arrangements of the Tables with some input from external parties, and feels that the presentation shown in the standard is the best way to present this complex information. To the degree possible, the SDT has attempted to make the arrangement of the three tables as similar as possible to address your concern.** **2. The cited sections of Table 1a, Table 1b, and Table 1c have been extensively revised.** **3. The SDT modified the standard to address your comments by revising the description of these components within the tables and by modifying the Protection System definition.** **4. Note 1 to Table 1a, Table 1b, and Table 1c specify, "adjustment is required to bring measurement accuracy within parameters established by the asset owner based on the specific application of the component." Clause R4.3 has been added to the standard to require that the entity "initiate any necessary activities to correct unresolved maintenance correctible issue." Because corrective actions will vary widely in type and scope, it is difficult to specify when it must take place; simple corrective actions may occur rapidly, but highly involved actions may take an extended period to complete.** **5. Thank you for your comments concerning the evaluation of cell/unit internal ohmic values to the station base line at the Maximum Maintenance Interval in Table 1. Because trending is an important element of ohmic measurement evaluation, the SDT believes that extending the Maximum Maintenance Interval listed in Table 1 for evaluating internal ohmic values would not provide the necessary information for proper evaluation of the ability of the station battery to perform as designed.** **6. The SDT has defined the minimum activities and the maximum intervals necessary to implement an effective PSMP. Some entities may feel that they need to maintain Protective System components more frequently.**	
Exelon Generation Company,	1. Battery testing should be added to Table 1c for Station dc supply (that uses a battery and charger)

Organization	Question 10 Comment
LLC	2. Table 1c Condition based maintenance. Consider adding Battery Capacity Test on a 6-year interval regardless of other condition based maintenance performed. 3. Evaluating the measured cell/unit internal ohmic values to station battery baseline does not provide an evaluation of battery capacity please explain rational for maintenance activity. 4. If the Table 1a maintenance interval is reached and the entity is unable to perform the maintenance task, is it acceptable to install temporary external monitoring or other measures to defer the maintenance to Table 1b or Table 1c interval? Is it acceptable in Table 1b to substitute additional or augmented maintenance activities or operator rounds to extend intervals? 5. Table 1c for equipment with "continuous monitoring" states the maximum maintenance interval of "continuous" this does not seem correct wording consider revising to state "not required." 6. The NERC standard should be revised to include a specific allowance for a deferral or variances of a maintenance activity based on a formal technical evaluation. Nuclear generating units allow for deferrals and/or variances on certain equipment based on emergent conditions that would prevent safe isolation and/or testing of function. It should be noted that any deferrals and/or variances if justified are to be based on a formal evaluation and not based on work management or resource issues. 7. The maintenance intervals and maintenance activities should be referenced directly to a basis document to ensure guidelines have a specific technical basis (e.g., IEEE-450).

Response: The SDT thanks you for your comments.

1. The SDT has modified the standard in consideration of your comments concerning Table 1c. Within Draft 2 of the standard, testing of the battery is not required if all performance attributes of the battery are monitored.

2. The SDT has modified the standard in consideration of your comments concerning Table 1c and the need for testing to verify that the battery can perform as designed.

3. The SDT believes that this Maintenance Activity is a viable alternative that a Vented Lead-Acid or Valve-Regulated Lead Acid battery owner can perform at the Maximum Maintenance Interval of Table 1 in place of conducting a capacity test. See FAQ II-5-F (page 14) and FAQ II-5-G (page 14).

4. R2 of the standard establishes that the entity "ensure the components to which the condition-based criteria are applied (as specified in Tables 1b or 1c), possess the necessary monitoring attributes." It appears irrelevant as to when the monitoring system is installed within the Table 1a monitoring interval, as long as the monitoring satisfies the attributes established in Table 1b or Table 1c as appropriate. If operator rounds, etc, are performed to the intervals established within the Table 1b general requirements, address the monitoring attributes specified within the Table, and are appropriately documented, they meet the requirements. However, it seems to the SDT that any temporary monitoring, etc, will have to be in place BEFORE you are overdue on maintenance and therefore out of compliance.

5. The Maintenance Activities describe that maintenance is actually being performed continuously via the monitoring system. Stating "continuous" for the interval provides a valuable link to FERC Order 693, which directs NERC to establish maximum maintenance intervals.

Organization	Question 10 Comment
6. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue. **7. IEEE Standards are voluntary unless they are adopted by an "authority having jurisdiction', thus the IEEE Standards could be adopted here in their entirety. However, they would require consistent and continual review by NERC to assure that they are, and continue to be, relevant. The SDT elected instead to use them as a source of material, and to include the relevant required tests within the NERC Standard.**	
FirstEnergy	1. BES reclosing schemes were recently questioned in a PRC-005-1 interpretation but there is no mention of reclosing schemes in the draft standard. This interpretation should be integrated into the requirements of PRC-005-2. 2. Lack of Exception Process - The standard as written does not reflect the fact that any one group, such as a TO performing maintenance on a BES, does not have full control over when an outage can be taken to perform maintenance activities. Especially regarding functional testing, where the equipment needs to be exercised resulting in some BES components being de-energized, it can be very difficult in certain parts of the T&D system to obtain the necessary outage to complete these tasks. Even with proper planning, changes in system conditions and unforeseen equipment problems in other areas can impact the ability to schedule an equipment outage appropriately. Accordingly, a TO can be penalized for not completing prescribed maintenance within prescribed limits due to factors outside of their control. This type of scenario has already been experienced where maintenance activities are scheduled upwards of a year in advance, and then inclement weather or system conditions outside of a TO's service territory (e.g. unanticipated generating unit shutdown) prevent the work from taking place. 3. The standard should provide some specific guidance to allow relief for such situations, or that properly incents or even requires independent system operators (ISOs) and other outside groups to also ensure maintenance is completed within prescribed intervals. If a TO properly considers factors such as weather (not scheduling critical outage during middle of summer), resource commitment, schedule (the requested outage window is at least one year before maximum interval is met), time of day (performing work during afterhours period when load is down) etc. then if outages are still denied, that the TO is not penalized for being out of compliance as maximum intervals are exceeded. This suggested "exception process" should provide requirements for all parties involved, both those performing the maintenance as well as those controlling and overseeing the system. There should be required documentation to prove that the parties on both sides made proper efforts to complete the required maintenance, as well as discuss conflict resolution. 4. With regard to the phrase "including identification of the resolution of all maintenance correctible issues" in Req. R4, we feel that this requirement should be a subset of R4 since it is part of the implementation of the PSMP. We suggest removing the phrase from the main requirement of R4 and creating a new 4.3 as follows:"4.3. For all maintenance programs, identify resolutions for all encountered maintenance correctible issues and take corrective action within a time period suitable for maintaining reliability

Organization	Question 10 Comment
	of the affected protection system." 5. With regard to the proposed modification of "Protection System", we suggest adding the word "devices" after "voltage and current sensing". This would also match what appears to be the SDT's intended wording as shown in the Supplementary Reference Document sec. 2.2. Also, we suggest modifications to the proposed definition to add clarity to the types of communications system protection and the voltage and current sensing devices. The following is our suggestion for wording of the definition:"Protective relays, communication systems used in communications aided (or pilot) protection, voltage and current sensing devices and their secondary circuits to protective relays, station DC supply, and DC control circuitry from the station DC supply through the trip coil(s) of the circuit breakers or other interrupting devices." 6. Protection System Communication Equipment and Channels - Some power line carrier equipment has automatic testing and remote alarming and some that does not. For other relay communication schemes (e.g., tone transfer trip ckts), if the circuit travels over our private communications network (fiber or microwave radio), the communication equipment is remotely monitored/alarmed. In other cases it is not remote monitored. We ask for clarification as follows: As part of our maintenance program, we check that signal level, reflected power, and data error rate are all within tolerance at the interface between the end equipment and the communication link. Our question is: Does this meet the intent of the proposed requirements in PRC-005-2 for maintenance activities for Protection System Communication Equipment and Channels? Or do the requirements ask for something beyond this? 7. We suggest combining 4.2.2, 4.2.3 and 4.2.4 to read as a new 4.2.2 "Protection System components which are installed as an underfrequency load shedding, under voltage load shedding or Special Protection System for BES reliability."

Response: The SDT thanks you for your comments.

1. The SDT is required to include/adopt material from approved interpretations within the standard. In the case of reclosing relays, the referenced interpretation stated that reclosing relays are NOT included, and the draft standard excludes them.

2. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue.

3. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive. Please refer to Section 8 (page 9) of the Supplementary Reference Document for a discussion on this issue

4. The SDT has modified the standard in consideration of your comment. Requirement R4, Part 4.3 was added and now reads: Assure either that the

Organization	Question 10 Comment
components are within acceptable parameters at the conclusion of the maintenance activities or initiate any necessary activities to correct unresolved maintenance correctable issues[4]. **5. The SDT believes that your suggestions regarding the Protection System definition may address predominant current technology relatively accurately, but may be constraining with regards to emerging technologies.** **6. If there is remote monitoring of the Channel, then Level 2 requirements indicate a 12 calendar year interval for the tests you describe. If the system is unmonitored a manual check back or a check of the automated check back is required at a 3 month interval. Unmonitored systems would also have the signal level, reflected power and data error rate check done on a 6 year interval.** **7. The SDT elected to list these components within separate subrequirements in order to maintain linkage to the legacy PRC-008, PRC-011, and PRC-017 standards. Your suggestion may be better adopted in a future revision of this standard (following approval of PRC-005-2).**	
Dynegy	1. The proposed definition of Protection System needs further clarification. Suggest changing wording around DC supply to read as follows: "...and DC control circuitry associated with protective devices from the station DC supply". 2. Suggest revising Section 4.2 to separate time based program as its own item under R4.3. 3. Change title on Table 1a to clarify level 1 monitoring as time based.
Response: The SDT thanks you for your comments. **1. The SDT has modified the standard in consideration of your comment. The following phrase was added to the definition:** and associated circuitry from the voltage and current sensing devices **2. R4.1 currently addresses implementation of maintenance programs per Table 1a, Table 1b, and Table 1c as different "flavors" of a time-based program, depending on the degree of monitoring present for the various components. The SDT feels that this is the correct approach. R4.2 specifically addresses performance-based maintenance, and does not seem relevant to the text of your comment.** **3. The SDT has modified the standard in consideration of your comment and added "Time-based" to the title of Table 1a.**	
MRO NERC Standards Review Subcommittee	A. In the applicability section 4.2.5.5, change the statement to say, "Protection systems for BES connected station-service transformers for generators that are part of the BES." B. In the applicability section 4.2.5, change the statement to replace "are part of" with "directly connected to". The "are part of" will be left to interpretation. Please indicate the added reliability benefit by collecting this in Table 1a Page 9 protection system

[4] A maintenance correctable issue is a failure of a device to operate within design parameters that can not be restored to functional order by repair or calibration while performing the initial on-site maintenance activity and that requires follow-up corrective action.

Organization	Question 10 Comment
	communication equipment and channels. C. If a breaker failure relay is also being used for sync-check, is it required to verify the voltage inputs since they are used for a closing function and not a tripping function? It is understood that the current inputs would have to be verified since these are used for breaker failure tripping. D. Please clarify requirement R1-1.1, does one have to individually list out each Protection System and its associated maintenance activities or can the PSMP be a generalized procedure that covers each of the components in all of a utility's Protection Systems? E. All references to breakers should be eliminated; thus, eliminate breaker trip coils. Breakers are primarily mechanical in nature and should be excluded similar to mechanical relay systems such as sudden pressure relays. F. Clarify that trip coils checks or tests can be verified through alternate means other than physically tripping the coil or potentially requiring system outages to physically trip a coil. Alternate tests could consist of checking self monitoring relays, continuity lights, etc. Trip coil tests could require transmission line outages which can be denied by regulatory authorities due to system conditions beyond an entity's control. Significant delays of months or longer could occur to obtain a transmission line outage. Further, potentially requiring transmission line outages for trip coil test could harm BES reliability by increase the number of force transmission line outages due to testing. System reliability could be significantly negatively impacted anytime testing on trip circuits is performed due to human errors causing outages or regional disturbances. G. One item R1.3 (inclusion of batteries) was questioned as why this was specifically called out. It should be part of the definition. H. Define the term “condition-based”. I. The format of the tables is poor with 17 line items addressed in each. It is difficult to relate one table to another because they are not consistent with regard to the type of components. For example table 1a references of components a “breaker trip coil (only)” and the 1b references “trip coils and auxiliary relays”. J. R1.1 please add “as they apply to the applicable entity”. As stated now, all three tables must be accomplished. K. Please add the words “time based maintenance methods” to table 1a for clarity in the heading. L. Table 1b under general description, last sentence the word “elements” should be replaced with “maintenance activities” which will provide exactly what is intended. M. Table 1b, if maintenance activities for level 2 monitoring include level 1 maintenance activities, then redundant activities in table 2 that are contained in table 1 should be removed (the same for table 3 to table 2 to table 1). N. If an entity maintenances a protective relay such that it is included in level 2 monitoring (a Condition Based Maintenance program) and this relay is considered to have a maximum interval of 12 years, does the entity need to also perform the maintenance activities for level 1 monitoring since the table 1b header indicates, “General Description: Protection System components whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for

Organization	Question 10 Comment
	alarmed failures. Monitoring includes all elements of level 1 monitoring with additional monitoring attributes as listed below for the individual type of component"?

Response: The SDT thanks you for your comments.

A. The station-service transformer impacts proper operation of the BES generator, whether the station service transformer is connected to the BES (for example, at 138 kV) or not (for example, connected at 46 kV). (See FAQ III-2-A, page 20)

B. This suggestion may actually bring a small, non-BES, generator facility that is connected to the BES into scope. For example, if a Region specifies that any generator greater than 20 MVA connected at 100 kV or above is BES, your suggestion would bring a 10 MVA generator (similarly connected) into scope. Clause 4.2.5 currently limits applicability to BES generators.

C. No. The maintenance activities for this component have been modified to clarify.

D. The entity may use whatever method it wishes, but the documentation of the program and the implementation of the program needs to be adequate to satisfy the Compliance Enforcement Authority that the program meets the requirements of the standard. Please be advised that all requirements of the standard must be met, including that the relevant activities in the Tables are performed.

E. The SDT believes that the breaker trip coils are a vital electrically-operated component of the DC control circuit, and they therefore must be included. For testing the breaker trip coil, the breaker must be observed to trip; however, such additional testing such as travel recorder, breaker timing, etc need not be performed to satisfy PRC-005.

F. The SDT considers that the electro-mechanical devices (trip coils, aux relay coils, etc) need to be periodically exercised to assure that they operate properly. Much of the rest of the control circuit can be verified by monitoring, including continuity of the coils, but this doesn't assure operating integrity of these devices. An entity is necessarily obligated to manage its maintenance program to complete the necessary activities on time, and various other NERC standards address the management of risk related to planned outages.

G. In the Protection System Maintenance – Frequently Asked Questions (FAQ) document (FAQ IV-3-G, page 26.) and Supplementary Reference Document Section 15.4 (page 23), the Drafting Team explains why batteries are excluded from PBM and the standard should include all batteries associated with a Protection System in a time-based program.

H. The SDT declines to introduce a defined term for this. Table 1b and Table 1c identify condition-based maintenance to include consideration of the known condition of the component within condition-based maintenance. The Supplemental Reference Document (Section 6, page 8) and the FAQ (V-3, page 38 and V-4, page 39) also describe condition-based maintenance considerations.

I. The SDT has modified to Tables to make them more consistent with each other.

J. The SDT has modified the standard in consideration of your comment. The original Pwas replaced with a new Part 1.1 and a new Part 1.3 was added as shown below,

1.1. Identify all Protection System components.

1.3 For each Protection System component, include all maintenance activities specified in Tables 1a, 1b, or 1c associated with the maintenance method used

Organization	Question 10 Comment
per Requirement 1, Part 1.2. **K. The SDT has modified the standard in consideration of your comment - and added "Time-based" to the title of Table 1a.** **L. The SDT has modified the standard in consideration of your comment. The revised language does not use the word, "elements" – it reads:** **M. The SDT disagrees. Repeating the activities in Table 1b or Table 1c allows the entity to not refer back to the previous table.** **N. If an entity decides to implement Table 1b for qualified components, the activities in Table 1b supersede the comparable activities in Table 1a. Requirement R1 has been modified to clarify.**	
CenterPoint Energy	a. CenterPoint Energy believes the existing maintenance standards are preferable to the approach embodied in this proposal. However, if most entities agree with the SDT's approach, CenterPoint Energy recommends deleting Under-Frequency Load Shedding (UFLS) and Under-Voltage Load Shedding (UVLS) system equipment from the scope of this proposal because the performance requirements for UVLS and UFLS are substantially different from transmission and generation protection schemes. Few would argue that protection schemes that clear faults on the Bulk Electric System must be very reliable, much more reliable than schemes that shed distribution load for under-voltage or under-frequency situations. If an entity plans to shed a contemplated level of load for a contemplated set of circumstances based upon planning simulations, that plan would translate into a certain number of distribution feeders that are reasonably predicted to shed a load amount that is reasonably close, but not exactly equal (unless by chance) to the contemplated amount of load shed. For example, if a certain number of distribution circuits equals 10% of the entity's load during one time (such as system peak), that same amount of distribution circuits will almost certainly equal a different percentage of the entity's load at other times. So, if hypothetically 100 distribution circuits are armed with UVLS or UFLS relays set a given trip point, the actual percentage of load that will be shed will vary under different system conditions. Therefore, if 95 of the distribution circuits actually trip on one occasion and 98 trip on another occasion, the difference in system performance is immaterial because the exercise is not that precise, especially when planning simulation uncertainties are also introduced into the picture. For these reasons, CenterPoint Energy believes it is unreasonable to impose a high level of rigidity into load shedding schemes when the designs of the schemes inherently do not depend on such rigidity. If the SDT agrees, then the revised standard would not be applicable to Distribution Providers, and 4.1.3 can be deleted. b. CenterPoint Energy also disagrees with the proposed expansion of the Protection System definition. The present definition does not include trip coils; and correctly so, as trip coils are part of the circuit breaker. A protection system has correctly performed its function if it provides tripping voltage up to the breaker's trip coils. From that point, the breaker can fail to timely interrupt fault current due to several factors such as a binding mechanism that affects breaker clearing time, a broken pull rod, a bad insulating medium, or bad trip coils. Local breaker failure protection is installed to address the various possible causes of circuit breaker failure. Planning standard TPL-001 tables 1C and 1D specifically support the present definition, as Delayed Clearing is noted as due to "stuck breaker or protection system failure".
Response: The SDT thanks you for your comments.	

Organization	Question 10 Comment
a. The four legacy standards are combined here in response to several suggestions, including from FERC (in Order 693) because of substantial equipment similarities. For the reasons that you note, the activities specified for UFLS and UVLS protection are somewhat less comprehensive than those for fault protection. **b. The SDT contends that the trip coil itself is an integral and essential component of the station control circuitry, and it must be assured that the trip coil operates. The SDT has also been diligent in excluding any facets of the breaker mechanism from consideration, thereby excluding consideration of many of the failure types listed. Many breaker failure schemes are designed with the presumption that the trip coil is properly initiated, and are more focused on mechanism failures.**	
NextEra Energy Resources	a. The level of effort that will be required to be in compliance in accordance to PRC-005-2 is substantial. Also, it will be difficult to create one maintenance program for all NextEra Energy sites that establishes maintenance intervals based the implementation of a combination of the three allowable types of maintenance programs (time-based, condition based, and/or performance based maintenance). As a result, a high risk exists that something will be missed or carried out incorrectly. b. What is the implementation period? How will the standard be implemented in relation to the entity's maintenance scheduled in accordance with existing intervals specified in the current Protection System Maintenance and Testing Procedure that meets the requirements of PRC-005-1 but will exceed PRC-005-2's established maximum intervals? Once PRC-005-2 becomes mandatory, entities should not be required to re-do testing in accordance with the new intervals. Instead, entities should be allowed to implement the newly established intervals after the last known cycle. c. Protection System Maintenance Program (PSMP): (c1) The PSMP definition would be better defined if the first sentence was changed to "An ongoing program by which Protection System components are kept in working order and where malfunctioning components are restored to working order." (c2) Please clarify what is meant by "relevant" under the definition of Upkeep. Should "relevant" be changed to "necessary"? (c3) The definition of Restoration would also be more explicit if changed to:The actions to return malfunctioning components back to working order by calibration, repair or replacement. (c4) Please clarify the definition of Restoration. For example, if a direct transfer trip system has dual channels for extra security even though only one channel is required to protect the reliability of the BES and one channel fails, must both be restored to be compliant? d. Protection System (modification): (d1) Voltage and current sensing inputs to protective relays" should be changed to "voltage and current sensors for protective relays." Voltage and current sensors are components that produce voltage and current inputs to protective relays. (d2) "Auxiliary relays" should be changed to "auxiliary tripping relays" throughout PRC-005-2, FAQ and the Draft Supplementary Reference.

Organization	Question 10 Comment
	(d3) The word "proper" should be removed from the standard. It is ambiguous and should be replaced with a word or words that are clear and concise. e. Additionally, NextEra Energy concurs with the following comments made by other entities: (e1) PRC-005 Sect B (R2): More clarity needs to be provided. Does this requirement require the utility to document the capabilities of its various protection components to determine fully and partially monitored protection systems? If so the requirement for such documentation should be clearly spelled out. Usually each requirement has a measurement (of compliance) and I'm not clear how this will be done. (e2) PRC-005 Sect B (R4.1): A "grace period" similar to the NPCC Criteria should be considered in case it is not possible to obtain necessary outages.

Response: The SDT thanks you for your comments.

a. We agree that the effort may be substantial. However, the effort and compliance risk can be minimized by simply implementing Table 1a, together with R1 and R4.

b. A proposed Implementation Plan was posted with this draft of the standard, and will continue to be posted with future drafts (including ballot drafts when the standard reaches that stage). Please review the posted Implementation Plan.

c1. The SDT does not believe that the suggested change is substantive, and sees no reason to make it.

c2. Some updates may not affect the operation of the device as applied, and therefore are not relevant. "Necessary" would imply an additional level of review to determine whether the device would operate properly without the updates, while "relevant" simply implies that the update applies to the function.

c3. The SDT does not believe that the suggested change is substantive, and sees no reason to make it.

c4. The standard establishes that all components need to be fully maintained, and that they will function as designed. The SDT appreciates that some "restoration" activities may take an extended time to complete, but also contends that restoration to the designed condition is a vital element of maintenance.

d1. The SDT has modified the standard in consideration of your comments.

d2. "Auxiliary tripping relays" may exclude essential other internal Protection System functions. Therefore, the SDT declines to adopt this suggestion.

d3. "Proper", "working condition", "correct", etc, are all somewhat subjective terms that address the application-specific requirements related to the specific use. For example, one entity's design standards may require that an electromechanical relay be within a 2% tolerance of the ideal operating characteristics, while another may only require that it be within 5%. Each of these is proper, correct, etc, for the application.

e1. The requirement establishes that an entity be able to prove that the specified monitoring attributes are met. There may be many methods of documenting this – see Section 15.6 of the Supplemental Reference Document (page 24) which was posted with this standard. Measures, etc, will be included with the next posted draft of the standard.

<table>
<tr><th>Organization</th><th>Question 10 Comment</th></tr>
<tr><td colspan="2">e2. The SDT is concerned that a “grace period”, if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a “grace period” would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document for a discussion on this issue.</td></tr>
<tr><td>City Utilities of Springfield, MO</td><td>As proposed, this standard is very long and complex. Additionally, in requirement R1, bullet 1.1 ought to state “For each component used in each Protection System, include all “applicable” maintenance activities specified in Tables 1a, 1b and 1c”. For instance, if every component has continuous monitoring, why should the program include 1a and 1b?</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments. The SDT has modified the standard in consideration of your comments. The original Part 1.1 was replaced with a new Part 1.1 and a new Part 1.3 was added as shown below,
1.1. Identify all Protection System components.
1.3 For each Protection System component, include all maintenance activities specified in Tables 1a, 1b, or 1c associated with the maintenance method used per Requirement 1, Part 1.2.</td></tr>
<tr><td>Austin Energy</td><td>Austin Energy is meticulous in adhering to the current maintenance standard and is convinced that its current maintenance and documentation program is adequate to maintain its reliable electric power system.
1. Austin Energy appreciates the good intentions of the SDT but believes that the approach taken increases complexities to the maintenance process, introduces unwarranted workload in excessive documentation, is inflexible towards system configuration and experience, and is over prescriptive in nature. The approach also fails to distinguish the harmful effects of over-maintenance, increasing reliability risk due to human error and ultimately affecting the overall performance and reliability of the system.
2. Another concerning issue is the addition of the breaker trip coil to the protection system definition. Our position is that the trip coil should be part of the breaker. The protection system would be considered operating correctly if it provided the output signal for the trip coil when expected. Hence the trip coil should be excluded from the new protection system definition.
3. Performance based maintenance as specified in the attachment is extremely difficult and cumbersome to navigate. The intricate requirements are difficult to comprehend and will entrap entities making a good faith effort to comply. We believe this approach may become burdened with undesirable consequences.
4. Last but not least, Austin Energy believes that under-frequency load shedding (UFLS) and under-voltage load shedding (UVLS) systems should not be included in the scope of this new proposal. UFLS and UVLS are a wholly different entity as compared to the Bulk Electric System (BES). Rigidity imposed onto distribution system equipment, operating schemes and performance is uncalled for and overreaching.</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments.
1. The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address</td></tr>
</table>

Organization	Question 10 Comment
observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Standards should be clear and unambiguous. The SDT has therefore defined the minimum activities necessary to implement an effective PSMP. To minimize system impact of such maintenance and possible errors, the maintenance necessarily should be scheduled at a time that minimizes the risks. **2. The SDT contends that the trip coil itself is an integral and essential component of the station control circuitry and it must be assured that the trip coil operates. The SDT has also been diligent in excluding any facets of the breaker mechanism from consideration.** **3. If an entity considers that a PBM would be difficult to implement, they may choose to implement simple time-based maintenance (Table 1a) and/or condition-based maintenance (Tables 1b and Table 1c). This option is provided for those who elect to take advantage of the opportunities presented.** **4. The four legacy standards are combined here in response to several suggestions, including from FERC Order 693 because of substantial equipment similarities. The SDT disagrees that the requirements for UFLS and UVLS are “uncalled for and overreaching”, and has specified less stringent requirements for these devices.**	
Progress Energy	Comments: 1- Requirement R4 “Each Transmission Owner, Generator Owner, and Distribution Provider shall implement its PSMP, including identification of the resolution of all maintenance correctible issues as follows: “ Based on the definition provided (A maintenance correctable issue is a failure of a device to operate within design parameters that can be restored to functional order by calibration, repair or replacement.) Pr ogress Energy believes that this will become a potential tracking issue. To maintain all of the data required to meet this definition can be onerous. 2- The biggest concern with the proposed PRC is that for many entities, the proposed maintenance and intervals will greatly increase the entities workloads. There are not enough relay technicians available to handle this increased workload across the country. 3- The Implementation Plan for R2, R3, and R4 identified in the Draft Implementation Plan for PRC-005-02, dated July 21, 2009, is very reasonable. This plan recognizes that it is unrealistic to expect entities that are presently using intervals that exceed the maximum allowable intervals to immediately be in compliance with the new intervals. It allows implementation to be implemented across the maximum allowable interval. This is a reasonable approach for the following reasons: a. Sufficient resources are not available to perform the additional maintenance proposed on an accelerated basis. b. It allows the staggering of the PMs so that resource loading can be balanced. Without the ability to stagger the PMs, there would be an initial “bow-wave” of PMs and future “bow-waves” each time the interval is up. 4- The Implementation Plan for R1 identified in the Draft Implementation Plan for PRC-005-02, dated July 21, 2009, is not reasonable. The implementation plan requires entities to be 100% compliant three months following approval of the PRC. This is not a reasonable timeframe given the program changes required, including: a. A massive effort to review circuit schematics to determine whether equipment meets the definition of partial-monitored or

Organization	Question 10 Comment
	unmonitored. b. Many procedures, basis documents, and job plans will need to be revised or created. c. The work management tool will have to be modified to reflect the new intervals. 5- PRC-008-1 placed only the relays associated with UFLS in the compliance program. Contrary to PRC-008-1, the draft PRC-005-02 places all components (relays, instrument transformers, dc supply, breaker trip paths) in the compliance program. This forces much of the distribution-level components to be placed in the compliance program. 6- The response to Item 2A of the FAQ Document, page 17, seems to indicate that commissioning test results do not have to be captured as the initial test record, only the in-service date. Is this a correct interpretation of the response? 7- Table 1a (Unmonitored Protection Systems) seems to indicate that a complete functional trip test must be performed for the UFLS/UVLS protection system control circuitry. This wording is identical with the wording for the protection system control circuitry (except UFLS/UVLS) table entry. This implies that UFLS/UVLS functional testing should include tripping of the feeder breakers for these unmonitored systems. Table 1b (Partially-Monitored Protection Systems) indicates that actual tripping of circuit breakers is not required under the UFLS/UVLS control circuit functional testing. Is this because trip coil continuity is being monitored and alarmed under Level 2 Monitoring? Must feeder breakers be tripped during the functional testing if the trip coil continuity is not monitored and alarmed (unmonitored protection system)? 8- All standards to be retired should be specifically listed in the Implementation Plan.

Response: The SDT thanks you for your comments.

1. **Requirement R4.3 has been added to the standard to address some of these concerns. It reads as follows:**

   R4. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement its PSMP, including identification of the resolution of all maintenance correctable issues as follows:

   4.3. Assure either that the components are within acceptable parameters at the conclusion of the maintenance activities or initiate any necessary activities to correct unresolved maintenance correctable issues.

2. The SDT understands that workloads may increase. However, with increasing sensitivity to degraded system performance, the increased attention to Protection System maintenance is critical to BES reliability. NERC's analysis of major system events reveals that Protection System maintenance is a contributing factor to many major system problems.

3. The SDT appreciates that you recognize these issues which were central in developing the Implementation Plan.

4. Table 1a provides activities and intervals for components for which Level 2 or Level 3 maintenance cannot be fully justified. Additionally, considerable time can transpire between successful balloting and regulatory approvals and major elements of the standard will be largely established even well before balloting. Entities are encouraged to proactively begin making the necessary program adjustments.

Organization	Question 10 Comment
5. PRC-008 currently addresses "UFLS equipment" which is a bit vague. Arguably, the identified components within PRC-005-2 may be regarded as various portions of "UFLS equipment". The SDT contends that the indicated activities are necessary, and notes that some of the activities are less stringent than for other Protection System components. **6. FAQ IV-2-A, page 22) now indicates that commissioning records are one option to establish the start date of maintenance intervals, and to establish the baseline.** **7. The Tables have modified to clarify that actual tripping of the breakers is not required for Protection System control circuitry for UFLS/UVLS only.** **8. The SDT agrees. The Implementation Plan will be modified to indicate retirement of the four legacy standards upon the completion of the Implementation Plan.**	
Nebraska Public Power District	Definition of Terms: 1. Footnote 2 for R4 defines a "maintenance correctable issue". This should be added to the Definition of Terms section. 2. Sections 4.2.5.4 and 4.2.5.5 inappropriately extend Generator Protection Systems to Station Service Transformers. These are components necessary for plant operation however they are not part of the generator protection scheme. This conclusion is supported by the explanations on page 16 of the FAQ. 3. The FAQ states the operation of the listed station auxiliary transforms protective relays would result in the trip of the generating unit and, as such, would be included in the program. The FAQ goes on to state that relays which trip breakers serving station auxiliary loads such as pumps, fans, or fuel handling equipment, etc., need not be included in the program even if the loss of those loads could result in a trip of the generating unit. The FAQ appears to be inconsistent. Station auxiliary transformers are included because they would result in the trip of the generating unit while other loads such as pumps, fans, etc., are excluded even if their trip could result in a trip of the generating unit. In my opinion, the station service transformers like pumps, fans, etc. are components necessary for plant operation but not necessary for generator protection and should therefore be excluded from PRC-005-2 by removing Sections 4.2.5.4 and 4.2.5.5 from the standard and modifying the FAQ accordingly. 4. R1 (1.1) First sentence: "For each component used in each Protection System..." is ambiguous. The sentence should be revised to say..."For each Protection System component, include all maintenance activities specified in Tables 1a, 1b, and 1c." This limits the components to only those identified by the definition of a Protection System. 5. R2 End of sentence: "possess the necessary monitoring attributes." is ambiguous. The sentence should be revised to say..."possess the monitoring attributes identified in Tables 1b or 1c." This specifically defines which attributes are necessary. 6. R4 I am concerned with including the phrase "including identification of the resolution of all maintenance correctible issues". Providing evidence of implementation of the PSMP will require the collection and submittal of all work documents that restored a device to functional order by calibration, repair, or replacement. It is reasonable to assume that appropriate corrective actions were taken for each specific situation. Identification of the resolution will add a significant documentation burden without adding to the reliability of the BES. Implementation of the PSMP may be evidenced without including identification of the resolution of all

Organization	Question 10 Comment
	maintenance correctible issues. It is interesting to note that nowhere in PRC-005-2 does it state that you have to take corrective actions to return a component to normal operating conditions. "No action taken" can be the resolution taken by the utility of a maintenance correctible issue.
Response: The SDT thanks you for your comments. **1. Establishing this term within the "Definition of Terms" would add this to the NERC Glossary. Instead, the SDT believes that this term is relevant only to this Standard, and that establishing it in the Glossary of Terms rather than simply as a term within this standard would expose entities to potential compliance exposure by having to refer to the Glossary to implement the standard.** **2. Station service transformers are system components and the Protection Systems on those system components must be maintained as indicated in this standard. (See FAQ III-2-A, page 20)** **3. Many of the components (pumps, fans, etc) are redundant, and a plant may be able to withstand loss of one of these. However, the loss of the station service transformer will result in simultaneous loss of many such elements, and will result in immediate plant shutdown. Also, the station service transformers may be necessary to achieve an orderly plant shutdown, and the loss of a station service transformer may result in a more abrupt plant shutdown. Improper Protection System performance due to maintenance issues must not be the cause of such an event. (See FAQ III-2-A, page 20)** **4. The SDT has modified the standard in consideration of your comment. The original Part 1.1 was replaced with a new Part 1.1 and a new Part 1.3 was added as shown below,** 1.1. Identify all Protection System components. 1.3 For each Protection System component, include all maintenance activities specified in Tables 1a, 1b, or 1c associated with the maintenance method used per Requirement 1, Part 1.2. **4. The SDT has modified the standard in consideration of your comment. The requirement was modified to read as follows:** **R2. Each Transmission Owner, Generator Owner, and Distribution Provider that uses condition-based maintenance intervals in its PSMP for partially or fully monitored Protection Systems shall ensure the components to which the condition-based criteria are applied, possess the monitoring attributes identified in Tables 1b or 1c.** **6. A fundamental tenet of compliance is that "if it's not documented, it's not done." Therefore, the documentation you describe will likely be necessary to demonstrate compliance. The PSMP definition, the new R4.3, and the General Requirements of each Table all establish that maintenance-correctable issues need to be resolved. If there is a maintenance-correctable issue, "no action taken" does not seem to be an acceptable response.**	
Florida Municipal Power Agency, and its Member Cities	1. Facilities applicability 4.2.2, due to the changes in applicability of the draft PRC-006, ought to refer say something like UFLS which are installed per requirements of PRC-006 rather than per ERO requirements. 2. In requirement R1, bullet 1.1 ought to state "For each component used in each Protection System, include all "applicable" maintenance activities specified in Tables 1a, 1b and 1c". For instance, if every component has continuous monitoring, why

<table>
<tr><th>Organization</th><th>Question 10 Comment</th></tr>
<tr><td></td><td>should the program include 1a and 1b?</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments.

1. The existing PRC-006 establishes that entities install UFLS in accordance with Regional requirements (which, by extension, are ERO requirements). In accordance with FERC Order 693, PRC-006 is currently undergoing revision to be a continent-wide standard, in which case it will itself be an ERO requirement. Clause 4.2.2 applies equally to either situation.

2. Requirement R1has been modified in consideration of your comment. The original Part 1.1 was replaced with a new Part 1.1 and a new Part 1.3 was added as shown below,

1.1. Identify all Protection System components.

1.3 For each Protection System component, include all maintenance activities specified in Tables 1a, 1b, or 1c associated with the maintenance method used per Requirement 1, Part 1.2.</td></tr>
<tr><td>American Transmission Company</td><td>1. General Comment: The requirements section of the standard seems acceptable.

2. NOTE: Why does R1.3 identify the inclusion of batteries? We believe that this should be part of the definition.

3. We believe that the team needs to define the term “condition-based”.

4. Does the Protection System definition in PRC-005-2 or interpretation of the standard and the tables line up with other NERC Standards?

5. The table formats (1a through 1b) are confusing and should be reconsidered. We found is difficult to relate one table to another. (No consistency in the Type of components)</td></tr>
<tr><td colspan="2">Response: The SDT thanks you for your comments.

1. The SDT thanks you for your support.

2. R1.3 specifies that batteries can be tested ONLY via TBM. That is the intent of the requirement. In the Protection System Maintenance – Frequently Asked Questions (FAQ) document (FAQ IV-3-G, page 26.) which accompanied the standard and in the Supplementary Reference Document, Section 15.4 (page 23), the SDT explains why batteries are excluded from PBM and the standard should include all batteries associated with a Protection System in a time-based program.

3. The SDT declines to introduce a defined term for this. Table 1b and Table 1c identify condition-based maintenance to include consideration of the known condition of the component within condition-based maintenance. The Supplemental Reference Document, Section 6 (page 8) and the FAQ (V-3, page 38 and V-4, page 39) also describe condition-based maintenance considerations.

4. The SDT was required to investigate all uses of this defined term with NERC standards and assure that these changes are consistent with the other</td></tr>
</table>

Organization	Question 10 Comment
applications. **5. The SDT has modified to Tables to make them more consistent with each other.**	
CPS Energy	Have several comments and questions: 1. I think that the way that the tables are done is confusing. My biggest complaint is that the "breakdown" of the Type of Component varies between the tables. For example, in tables 1a and 1B, you have Protective Relays, but in table 1c, you have Protective Relays and Protective Relays with trip contacts. This is a little confusing at times. 2. I also find the UFLS/UVLS requirements confusing as well. It can be confusing to figure out when the UFLS/UVLS has a separate requirement. Would prefer to see the UVLS/UFLS in separate tables; e.g. 2a, 2b, 2c. 3. SPCTF should provide the basis for how the intervals in table 1 were derived. While the supplemental describes that a survey of its members with a weighted average was used to determine the maintenance intervals. However, what is not clear is what exactly was surveyed in terms of components. Was it just relay calibration testing? Functional testing? What about communications, voltage and current sensing devices, trip coils, etc? Was UVLS and UFLS looked at separately from transmission? Was generation also considered as well? Why did values change from the SPCTF technical reference "Relay Maintenance Technical Reference" dated September 13, 2007? For example, UVLS/UFLS testing and calibration went from 10 years to 6 years for un-monitored, communications went from 6 months to 3 months for un-monitored, and instrument transformer testing went from 7 years to 12 years for un-monitored systems. What is the basis for the intervals? 4. The committee should reconsider the use of the term "A/D converters". The point of the requirement is to assure that the analog signal from the instrument transformer is correct to the processor. Two problems with just saying "A/D converters". One, it ignores the digital relay input transformers of microprocessor relays. The SEL-4000 test set can bypass these transformers. Would using this test set be adequate to test the "A/D converters"? Two, some relays, such as the SEL-311L, perform an A/D self-test. I do not think that the A/D self-test performs the testing that is being sought by the document. 5. Could a better example of "Calendar Year" be provided? Is it simply the years difference, or should the days be included as well? In your example in the reference document, you show that December 15, 2008 and December 31, 2014 as meeting the requirement of 6 calendar years. Would like to see a more exaggerated example. Would an unmonitored protective relay is calibrated on January 1, 2008 and then again on December 31, 2014 meet the "Maximum Maintenance Interval" of "6 Calendar Years"? 6. Does the standard address breakers and other switching devices that do not have "trip coils". Magnetic actuated circuit breakers, reclosers, and possibly other devices do not have trip coils to monitor or test. Do the trip coil testing and requirements fully take this account? If a breaker does not have a trip coil, is some other type of test required? Does not having a trip coil prevent extending the Protection System Control Circuitry interval to 12 years? 7. The requirement for testing Voltage and Current Sensing devices should be better thought out as to what is trying to be accomplished. On page 11 of the reference document, item 6 under "Additional Notes for Table" it states that "phase value and

Organization	Question 10 Comment
	phase relationships are both equally important to prove". In both the FAQ document (page 6, 3A) and the reference document (page 21, 15.2), several methods to verify the voltage and current sensing inputs to the protective relays and satisfy the requirement are given. However, these methods do not all seem to verify the same thing. Totalizing watts and vars on the bus verifies that the current transformers are correctly and providing correct signals to the relays, but do not necessarily verify that the voltage sensing device is necessarily correct if the same PT is used for all relays on the bus. Performing a saturation test on a CT and a ratio test on the PT does not verify the phase angle relationships, which is stated as important on page 11 of the reference document. What exactly needs to be accomplished by the Voltage and Current Sensing devices testing? That an analog signal is getting from the instrument transformer to the device? That the signal is an accurate representation of the measured quantity? What about frequency for UFLS relays, where voltage magnitude may not be that important? Do CT's need to be verified for multiple CT grounds? Do the any examples described necessarily find multiple ct grounds? 8. This standard should also address the ramifications of RRO's not allowing for equipment to be removed from service for testing. Either RRO's should be required to allow outages in some time frame or leeway should be given to entities that cannot get equipment out for maintenance because RRO's will not grant reasonable outage times for testing and maintenance. 9. Page 13 of the reference document states that the 3-month inspection should include checking that "equipment is free of alarms, check any metered signal levels, and that power is still applied." What is meant by "metered signal levels"? What does the term "metered" mean, specifically in terms of an on-off power line carrier scheme? 10. It appears that if a company on a TBM plan has shorter intervals than the maximum allowable of this proposed standard, the company would not be in violation if they did not meet their own plan but still met the intervals required by this proposed standard. Is this true? Could this actually reduce reliability of the BES if companies are now allowed to extend intervals to those listed in this document without any justification?

Response: The SDT thanks you for your comments.

1. The SDT has modified to Tables to make them more consistent with each other.

2. Many of the components of UFLS and UVLS are very similar to other generic Protection System components, with similar maintenance activities. The SDT has modified the Tables to clarify activities which apply specifically to UFLS and/or UVLS.

3. The SPCTF, in an earlier technical paper, provided descriptions of the derivation of the intervals, but this technical paper was not charged with developing a measurable standard. The SDT has used this information, as well as consideration of system and generation plant operating constraints, EPRI reports, IEEE surveys, and experience of SDT members and others, to develop the intervals in the tables. These intervals were also adjusted to address the SPCTF's recommendations about grace periods without providing grace periods. The SDT also considered intervals that supported establishment of systemic maintenance programs.

4. The SDT modified the standard in consideration of your comment. A/D converters are now discussed only in the Monitoring Attributes within Table 1c; otherwise, the relay must be confirmed to operate properly. However, the SDT did NOT define methodology.

5. Disregard the complete date and just look at the year portion. For a 6 calendar-year interval, if the test date was IN 2004, the next test date must be IN or

Organization	Question 10 Comment
before 2010. 6. Where relevant to the requirements of the standard, any of these devices apply similarly. Many of the alternate technologies mentioned do not seem relevant to BES Protection Systems, but instead to UFLS and/or UVLS systems. The required maintenance activities for these components do not require actual test tripping. 7. No single method of verification may be relevant for every imaginable situation. The activities relevant to Voltage and Current Sensing Devices have been revised in consideration of your comment. 8. Some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Allowing a "grace period" would create a standard that is not measurable. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue. Outages must be planned in accordance the Reliability Coordinators (RRO's, or RE's, have no role in this) to support reliable system operation. 9. "Metered signal levels" refer to the communication signal levels which are part of proper communications system function for certain equipment, such as power-line carrier systems. The SDT is continuing to align the three documents (Standard, Supplemental Reference, and FAQ) to assure consistency. 10. You will be held to compliance with your plan, whatever it is, under R4, but your plan must also adhere to the intervals established by NERC. As long as you still have elements subject to PRC-005-1, you need to comply with the program established for PRC-005-1. When you have fully implemented PRC-005-2, the requirements of PRC-005-1 no longer apply. However, the SDT hopes that entities that feel that a shorter interval is appropriate will continue to use that interval.	
JEA	1. Implementation Plan - Strongly encourage keeping the implementation plan and allow for an extension of the implementation plan for the time required to fund, design, procure, install and commission redundant protection systems for current non-redundant lockout systems at the lower kV levels of the BES. 2. Our present and past performance of LOR and auxiliary relays will support a PBM/CBM program that allows for a much longer time than the six years proposed for EM LOR trip testing. To use a TBM for LORs of six years, may in fact, lower the reliability of the BES due to the complete outages required, along with the detailed procedures that must be created and rigorously followed to perform these tests without subsequent load loss on the BES.
Response: The SDT thanks you for your comments. 1. If an entity expects to encounter difficulty in performing the maintenance specified in the standard, the SDT encourages them to begin implementation of the necessary features to support maintenance while the standard is still in a development or approval stage. 2. The SDT encourages you to begin assembling the documentation necessary to support a PBM for these components such that you may implement that PBM when the standard becomes effective.	
Consumers Energy Company	1. In Table 1a for Station dc supply it requires verification that no dc supply grounds are present. DC grounds are common

Organization	Question 10 Comment
	occurrences and the activity should be to document if dc grounds are present. 2. Please specify how cell to cell connection resistance is measured. 3. For station dc supply (battery is not used) change “Verify the continuity of all circuit connections that can be affected by wear and corrosion” to “Inspect all circuit connections that can be affected by wear and corrosion.” 4. Is “metered and monitored” equivalent to “alarming”? 5. If a component failure causes the unit to trip, what is the purpose of testing it? It will always test positive until the point of failure and that point is identified when the unit trips. 6. In the Facilities Section 4.2.5.4 “station service transformer” should be changed to “unit connected auxiliary transformer” to be consistent with Figure 2 of the Supplement Reference Document. 7. Facilities Section 4.2.5.5 should also include “System connected auxiliary transformers are excluded when only used for unit start-up.” 8. There should be an allow variance period (grace period) for the testing intervals. 9. The maximum allowable time periods should be in calendar years, defined as “occurring anytime during the calendar year.” 10. The following statement should be added to Requirement 1.2: “Identification at a program level is permissible if all components use the same maintenance method.”

Response: The SDT thanks you for your comments.

1. The SDT has modified the standard in consideration of your comments concerning dc grounds – the maintenance activity was revised to read, ‘Check for unintentional grounds.”

2. The IEEE Standards 1188 and 450 have very detailed descriptions of how to measure cell to cell connection resistance using a Micro-Ohm Meter.

3. Upon consideration of your comment, the SDT determined that it is important to both “check the continuity” and to verify the physical condition. Therefore, the standard has been modified to include both.

4. Not necessarily. “Metered and monitored” are more detailed than “alarming”. Alarms simply report an abnormal condition, while “metered and monitored” will probably actually report values.

5. In this case, testing of the component should assure that the component functions properly and thus does NOT result in an unintended trip of its system component, and that it WILL trip when called upon to do so.

6. The SDT contends that “station service transformer” is a more universal description for this component. The Supplemental Reference Document has been modified for consistency.

7. The SDT contends that “startup transformer” Protection Systems also need to be maintained per PRC-005-2. During startup, these components are

Organization	Question 10 Comment
critical for reliability. On the other hand, maintenance of the Protection Systems on these system elements should be somewhat easier to schedule. **8. The SDT considered this issue when developing the intervals, and realizes that some entities may need to perform certain maintenance activities more frequently to assure that the activities are performed within the required intervals. Specifically, for generation facilities, there would seem to be numerous opportunities within the 6-year or longer intervals to perform the required maintenance during a scheduled plant outage, and maintenance with shorter intervals can be characterized as non-intrusive maintenance, more of an inspection than anything else; the SDT believes that this maintenance can be done on-line. The SDT is concerned that a “grace period”, if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a “grace period” would not conform to this directive. Please refer to Section 8 of the Supplementary Reference Document (page 9) for a discussion on this issue.** **9. All multi-year periods ARE in calendar years. There are other essential shorter intervals, and the SDT does not agree that these can be extended to a minimum of one calendar year – most of these activities are “inspection” type activities. The SDT does not believe that it is necessary to define this term; “Calendar year” seems to be a very precise term in itself.** **10. To the degree that you can concisely describe your program this way, and demonstrate implementation of your program, it does not seem to the SDT that this modification to the requirement is necessary.**	
ITC Holdings	1. In the Definitions of Terms, the Protection System (modification) should include control circuits up to and including the trip coil of ground switches used in protection schemes. 2. Footnote 2 (Maintenance correctable issue) should be included in the Definition of Terms in the body of the standard.
Response: The SDT thanks you for your comments. **1. To the degree that the ground switch (or, more properly, the Protection System that operates the ground switch) is protecting a BES element, the SDT classifies the ground switch as an interrupting device.** **2. Establishing this term within the “Definition of Terms” would add this to the NERC Glossary. Instead, the SDT believes that this term is relevant only to this standard, and that establishing it in the Glossary of Terms rather than simply as a term within this standard would expose entities to potential compliance exposure by having to refer to the Glossary to implement the standard.**	
Entergy Services, Inc	1. It would be beneficial to also include an explanation or definition of the term “calendar year” in the standard. It is not readily apparent in the draft standard, especially in light of the new maximum interval requirements, that a task can be performed anytime between 1/1 and 12/31. 2. Although addressed in the FAQ and Supplement, the terms “Upkeep” and “Restoration” are referenced in the definitions section of the standard but are not used anywhere else in the document, or with regard to routine activities. They should be eliminated from the standard unless there are upkeep or restoration requirements.
Response: The SDT thanks you for your comments.	

Organization	Question 10 Comment
1. Disregard the complete date and just look at the year portion. For a 6-calendar-year interval, if the test date was IN 2004, the next test date must be IN 2010. **2. While "upkeep" is not used in the standard, the SDT has identified the term as a component of maintenance. "Restoration" is used in R4.3 and within the header of each Table.**	
AEP	1. Monitoring and tracking the activities prescribed in the standard seem too complex to manage at a level needed for auditable compliance. The activities prescribed seem to lean toward conventional protection systems and do not take into account newer special technology devices (High Voltage DC, Static Var Compensator and Phase Shifting transformer controls) and how there are to included. 2. R1 1.2 Does the draft standard require a basis for an entities" defined time based maintenance intervals or can an entity just move directly to the intervals prescribed and use the standard as its basis" 3. R4. This requirement seems to refer to failed equipment and its reporting. This corrective maintenance activity is outside of the interpreted preventative maintenance theme of the standard and adds another layer of complexity in compliance data retention. It also implies that a failed piece of equipment or segment could remain failed for the entire maintenance interval. 4a.Tables 1a & 1b. Station dc supply (that has as a component any type of battery) Interval: 18 months - This requirement incorporates specific gravity testing (where applicable). Although (where applicable) is not defined, it seems it refers to all non-sealed batteries. 4b. For sealed batteries, a more frequent internal ohmic test is prescribed. The same 18 month requirement incorporates ohmic testing which is essentially equivalent to specific gravity. Specific gravity and measure of internal temperature are invasive tests which subject personnel to handling acid and subject the battery to damage. If the logic for sealed batteries is to do more frequent ohmic testing why not allow more frequent ohmic testing as a substitute for specific gravity? We would suggest ohmic testing every 6 months with any questionable results rechecked using specific gravity. This eliminates excessive intervention into all cells and gives a validity check on the ohmic testing. 4c.For Ni-Cad the performance service test has no option (6 year intervals). Typically, the Ni-Cad can yield a low voltage indication; however testing the cells in pairs allows testing and finding bad cells. Why not offer a more frequent ohmic test for the Ni-Cads? 5. Facilities 4.2.1 and R1. "applied on, or are designed to provide protection for the BES." This may be in conflict with Regional Entity (RE) BES definitions. There needs to a clear understanding of what is included and what is not without regional differences. There should be no responsibilities or requirements of the RE. BES also takes on different meanings depending upon which of the many standards it is applied. Data Retention 1.4 Data retention for two intervals could mean that records would need to be kept for 24 years. This seems impractical. Could audit evidence be used in lieu of actual data for long intervals? 6. Tables: Where the interval is in months, the term "calendar" months should be used for clarification.

Organization	Question 10 Comment
	7. Table 1a:“verify the continuity of the breaker trip coil”. The SDT assumed that Trip Coil Monitoring (TCM) could be accomplished by verifying/inspecting red lights. This may be true in most cases, but there are designs that do not incorporate this type of TCM and the breaker would have to be exercised every 3 months if not operated by natural events unless the scheme gets replaced. This seems counterproductive to the reliability of the BES. The implementation plan does not take the time required for upgraded systems into consideration. 8. Table 1a DC Supply, 3 month interval “Verify no dc supply grounds are present.” Does this mean that you are non-compliant if you have a DC ground? This also needs to be clarified as to the amount of acceptable ground that could be present. Table 1a PS communications equipment channels 3 month interval: Do the activities imply that only alarms be verified and that no channel “playback” be performed? 9. If SPR relay or similar auxiliary relay is excluded as a protective relay, then do we not have to verify its tripping contact as part of the DC system? 10. Table 1a The exclusion of UVLS/UFLS from certain activities is confusing. Does trip coil monitoring not have to be performed on these systems? Tables: 11. Since PT and CT devices themselves are not included in the PS definition, then the word “devices” should be removed from the type of component column describing inputs to the relay. 12. Table 1a. Even though an entity may be on time-based intervals, would a natural occurring fault event reset the maintenance clock for the protection segment involved? 13. Assessment of Impact of Proposed Modification to the Definition of Protection System: Reclosing and certain auxiliary relays have been excluded from protection system definition. This new definition would have an impact on other PRC standards that use this term in its requirements, specifically the Misoperations investigation and reporting standards. These other standards, as written today, are not clearly written as to the application and assumptions as to what is included in a protection system. 14. Trip coil Monitoring: If the trip coil is actually part of the DC circuitry, then why is there a differing (shorter) interval for this series connected element?

Response: The SDT thanks you for your comments.

1. The SDT invites additional participation to address such devices.

2. There is no additional basis required for an entity to adopt the maximum allowable intervals established within the standard.

3. The SDT has modified the standard to require that an entity also initiate correction of maintenance-correctable issues. There is no time-period specified for actually correcting maintenance-correctable issues in recognition of the wide variety of activities that may be represented.

4a. The SDT has modified the standard in consideration of your comments concerning specific gravity not being applicable to non-sealed batteries. The

Organization	Question 10 Comment
maintenance activities no longer include any reference to specific gravity. **4b. The SDT has modified the standard in consideration of your comments concerning specific gravity and internal temperature. The maintenance activity associated with specific gravity and internal temperature was removed from the revised standard.** **4c. Presently there are no other options that are available today to verify that a Ni-Cad battery can perform as designed.** **5. NERC standards establish minimum requirements, which can be expanded on by Regional Entities. This standard does NOT place any requirements upon the Regional Entity. BES is a defined NERC and Regional Entity term which applies uniformly to the various standards. The Records Retention section has been modified to read as follows:** The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous on-site audit date, whichever is longer. **6. The SDT has modified the standard in consideration of your comment and the word, "Calendar" was added to clarify that the term "months" means "calendar months"** **7. The SDT has removed the cited requirement.** **8. The SDT has modified the standard in consideration of your comments concerning dc grounds (changed to "Check for unintentional grounds" and compliance FAQ II-5-I, (page 15) explains that the entity is responsible to determine if corrective actions are needed upon detection of unintentional dc grounds.** **9. Yes.** **10. The Tables have been modified to better delineate the specific activities related to components associated with UFLS/UVLS relays.** **11. The definition has been further modified to add these devices.** **12. Only to the degree that the Protection System operation for the natural fault verified the functions and "performed" the activities within the Table. See FAQ II-4-C, page 10 and Supplementary Reference Document, Section 15.3, page 22.** **13. The SDT, in accordance with the NERC Standard Development Procedure, analyzed all other uses of the defined term, "Protection System" within the NERC standards, and, in a document which was posted with the standard and other associated documents during the comment period, listed all other uses and concluded that there is no impact on the other uses. Reclosing relays are still not listed in the definition, but auxiliary relays, which previously were not listed and now are, were implicit in the previous "dc control circuits".** **14. The Tables have been modified to remove this shorter-interval specific activity.**	
Green Country Energy LLC	None
Georgia System Operations Corporation	None.

Organization	Question 10 Comment
Operations and Maintenance	None.
ENOSERV	On Table 1A, the maximum time lengths are too long, especially for electro relays. A prime example is when testing a KD relay on a yearly basis and most of the time needs to be adjusted because of how far off it comes out. Allowing entities to take their time up to six calendar years may be too long.
Response: The SDT thanks you for your comments. See the Supplementary Reference Document, Section 5.1, page 7.	
Xcel Energy	Please clarify if the following are subject to PRC-005-2 requirements: 1) a battery that is in a station where the only BES element is a UFLS scheme 2) batteries used only to support communication elements (microwave houses)
Response: The SDT thanks you for your comments. **1) The SDT has modified the standard to clarify that the only DC Supply maintenance activity relevant to UFLS is to verify the DC supply voltage.** **2) The proper functioning of such batteries (communication system) will be addressed by the verification and monitoring of the communications system, and by addressing maintenance correctable issues related to the communications system. See FAQ II-5-K, page 15.**	
BGE	1. PRC-005-2R1 1.2 Identify whether each Protection System component is addressed through time-based, condition-based, performance-based, or a combination of these maintenance methods and identify the associated maintenance interval. Comment: The existing standard PRC-005-1 requirement R1.1 says a maintenance program must include the maintenance and testing intervals and their basis. PRC-005-2 does not have a similar requirement, and the associated FAQ indicates the standard “establishes the time-basis for a Protection System Maintenance Program to a level of detail not previously required”. Does PRC-005-2 require evidence to support the basis for a defined maintenance interval, or is the basis now purely defined by PRC-005-2? 2. R2 Each transmission owner ....shall ensure the components to which condition-based criteria are applied....possess the necessary monitoring attributes? Comment: Depending on the evidence requirements that are enforced this could be a very large undertaking offsetting the benefit of extending intervals with CBM. It would be helpful to understand what the drafting team or other stakeholders would envision as appropriate evidence supporting this requirement. 3. R4 Each transmission owner ....shall implement its PSMP, including the identification of the resolution of all maintenance correctable issues as follows :4.1 ....within the maximum allowable intervals not to exceed those established in table 1a, 1b, 1c Comment: It’s inferred that this requirement applies to maintenance correctable issues that are discovered as a consequence of scheduled maintenance and not as a consequence of monitoring or misoperations. If that inference is incorrect the requirement

Organization	Question 10 Comment
	imposes an unequal playing field for the resolution of known correctable issues depending on the monitoring being employed, not to mention an unreasonably long allowance for the correction of some serious problems. On the other hand, the requirement imposes an unreasonably short period of time for the resolution of some issues that may be associated with short interval maintenance/inspection intervals, such as battery grounds. 4. Section D1.4 Data Retention? The Transmission Owner shall...retain documentation for two maintenance intervals.... Comment: Recognizing that in order to achieve compliance PS owners will execute scheduled maintenance on shorter intervals than the maximum requirement it's uncertain what this means. Example: Max interval for instrument transformers is 12 years, we maintain every six. Is the requirement for 24 years of data or 12? It seems like there ought to be an upper limit. 24 years is a very long time. Table 1a Protection System Control Circuitry (Breaker trip coil only); 3 month maximum interval; verify the continuity....of the trip circuit.....except for breakers that remain open for the entire maintenance interval. Comments: What's the failure-probability justification for this requirement when other similar dc control components have a maximum interval of 6 years? It seems like the SDT made an assumption that all trip coils are monitored by red lights and could be verified by inspection and said somewhat arbitrarily, "do it because you can". "Remaining open for the entire maintenance interval" is a poorly reasoned effort to arrive at a necessary exception. Even if the red-light-through-the-trip-coil assumption is accurate for a normally open breaker, it's unreasonable to demand that an inspection take place if it's closed at anytime during the interval. The actual time that its closed might be seconds or a few minutes, but that time would make the exception moot and put the owner out of compliance. On the subject of three month maximum intervals in general: One can agree that three months is about the right time for some of these inspections, batteries in particular. However as written, three months and a day is "out of compliance". More flexibility would avoid a lot of meaningless "technical fouls". How about four times a year not more than four months between each...or something like that. 5. Table 1aStation DC supply (that has as a component any type of battery); verify that no dc supply grounds are present? Comment: All grounds are not created equal. No guidance for acceptance criteria is given, nor is evaluation/acceptance criteria explicitly made the responsibility of the battery owner (as it is for relay calibration). Without any guidance the requirement of "no" grounds is open to unreasonable interpretation (there is always a ground if one considers a high enough resistance) and high impedance grounds that do not present a risk to the PS will consume effort and attention unnecessarily. 6. Station DC supply (that has as a component any type of battery); Measure to verify that the specific gravity and temperature of each cell is within tolerance? Comment: It is not clear that a specific gravity test provides any better data concerning battery health than an impedance test, but specific gravity testing is a requirement. Can the impedance test be performed as routine maintenance in lieu of a specific gravity test? 7. General Comment: It is not clear whether Communications batteries should be held to the same testing/maintenance requirements as the station battery. Communications batteries are in place to supply relatively low power electronic equipment and do not have to provide energy to trip a breaker. Simple monitoring of the channel may be sufficient to assure battery

Organization	Question 10 Comment
	availability, and a less rigorous maintenance plan may be appropriate based on the continuous monitoring and low duty of the battery. 8. FAQ Group by Monitoring Level A level 2 (partially) monitored Protection System or an individual component of a level 2 monitored Protection System has monitoring and Alarm circuits on the Protection System components. The alarm circuits must alert a 24-hour staffed operations center. Comment: The standard Table 1b, General Description for Level 2 monitoring is simply described as Protection System components whose alarms are automatically provided daily (or more frequently) to a location where action can be taken for alarmed features. This appears to be a conflict between the FAQ and the standard. The more stringent requirement of the FAQ, for the reporting facility to be manned 24 hours per day, could be read to imply a requirement for a specific time to respond to an alarm. Is there such a requirement? Is there an implied requirement to document the alarm condition and the response time?
Response: The SDT thanks you for your comments. **1. If a time-based or condition-based program is used according to Tables 1a, 1b, and 1c, no additional basis is needed. If the entity elects to use Performance-based maintenance, the activities in Attachment A must be used to establish the related basis.** **2. See FAQ V-1-D, page 22 for a discussion relevant to your comment.** **3. The SDT has modified the standard in consideration of your concern concerning the interval of checking for unintentional dc grounds and the ability to remove the unintentional ground from the dc system. R4 of The SDT has modified the standard to require initiation of the resolution of maintenance-correctable issues, rather than to identify their resolution. See FAQ II-5-I, page 15.** **4. The data retention section has been modified to read as follows:** The Transmission Owner, Generator Owner, and Distribution Provider shall each retain documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or to the previous on-site audit date, whichever is longer. **5. Both the standard and FAQ document have been modified in consideration of your comments concerning dc grounds to specify that it is up to the owner to determine if corrective actions are needed for unintentional dc grounds. See FAQ II-5-I, page 15.** **6. The standard has been revised to remove maintenance activities related to specific gravity.** **7. Communication system batteries are not included in the requirements for "Station Batteries". The entity must ensure proper operation of the relay communications circuit which would include adequate maintenance of the equipment including the communication system batteries The proper functioning of such batteries (communication system) will be addressed by the verification and monitoring of the communications system, and by addressing maintenance correctable issues related to the communications system. (See FAQ II-5-K, page 15.)** **8. The FAQ has been modified to remove this apparent additional requirement.**	
Transmission Owner	Protection System Maintenance Program (PSMP)

Organization	Question 10 Comment
	a. The PSMP definition would be better defined if the first sentence was changed to "An ongoing program by which Protection System components are kept in working order and where malfunctioning components are restored to working order." b. Please clarify what is meant by "relevant" under the definition of Upkeep. Should "relevant" be changed to "necessary"? c. The definition of Restoration would also be more explicit if changed to "The actions to return malfunctioning components back to working order by calibration, repair or replacement. d. Please clarify the definition of Restoration. For example, if a direct transfer trip system has dual channels for extra security even though only one channel is required to protect the reliability of the BES and one channel fails, must both be restored to be compliant? e. Protection System (modification) "Voltage and current sensing inputs to protective relays" should be changed to "voltage and current sensors for protective relays." Voltage and current sensors are components that produce voltage and current inputs to protective relays. f. "Auxiliary relays" should be changed to "auxiliary tripping relays" throughout PRC-005-2, FAQ and the Draft Supplementary Reference. g. The word "proper" should be removed from the standard. It is ambiguous and should be replaced with a word or words that are clear and concise.

Response: The SDT thanks you for your comments.

a. The SDT does not believe that the suggested change is substantive, and sees no reason to make it.

b. Some updates may not affect the operation of the device as applied, and therefore are not relevant. "Necessary" would imply an additional level of review to determine whether the device would operate properly without the updates, while "relevant" simply implies that the update applies to the function.

c. The SDT does not believe that the suggested change is substantive, and sees no reason to make it.

d. The standard establishes that all components need to be fully maintained, and that they will function as designed. The SDT appreciates that some "restoration" activities may take an extended time to complete, but also contends that restoration to the designed condition is a vital element of maintenance.

e. The critical task is to verify that the proper representation of the primary current and voltage signals will get to the protective relays. The "Type of Protection System Component" has been modified in an effort to clarify.

f. "Auxiliary tripping relays" may exclude essential other internal Protection System functions. Therefore, the SDT declines to adopt this suggestion.

g. "Proper", "working condition", "correct", etc, are all somewhat subjective terms that address the application-specific requirements related to the specific use. For example, one entity's design standards may require that an electromechanical relay be within a 2% tolerance of the ideal operating characteristics, while another may only require that it be within 5%. Each of these is proper, correct, etc, for the application.

Organization	Question 10 Comment
Ohio Valley Electric Corp.	1. R1.2 seems to require owners to establish there own intervals and basis. Compliance with these requirements should be based on the intervals that are in tables 1a, 1b and 1c. 2. R4 implies that all maintenance correctible issues must be resolved within the Maintenance Activity Intervals. A diligent effort to restore proper function of a system should not be penalized if it does not fall within the prescribed maintenance interval.
Response: The SDT thanks you for your comments. **The SDT has modified the standard in consideration of your comment. The Parts of Requirement R1 were modified to read as follows:** 1.1. Identify all Protection System components. 1.2 Identify whether each Protection System component is addressed through time-based, condition-based, performance-based, or a combination of these maintenance methods and identify the associated maintenance interval. 1.3 For each Protection System component, include all maintenance activities specified in Tables 1a, 1b, or 1c associated with the maintenance method used per Requirement 1, Part 1.2. 1.4 Include all batteries associated with a Protection System in a time-based program. **2. The SDT has modified the standard to require INITIATION of resolution, not the actual resolution. The revised footnote reads as follows:** A maintenance correctable issue is a failure of a device to operate within design parameters that can not be restored to functional order by repair or calibration while performing the initial on-site maintenance activity, and that requires follow-up corrective action.	
E.ON U.S.	1. Recently, NERC made an interpretation on PRC-005-1 which stated that battery chargers were not to be included as part of the standard. This version of the standard seems to be in direct conflict with that interpretation, and for the reasons stated above E.ON U.S. recommends that battery chargers not be included in the standard. E.ON U.S. believes that capacity or AC impedance only needs to be done to determine service life, and therefore a periodic testing of station DC supply does not seem necessary or prudent. 2. Regarding the "Retention of Records", retaining records of the latest test seems adequate. E.ON U.S. does not understand the point of retaining records for the past two test results. This is particularly true for equipment for which there are relatively long testing intervals, for example, 12 years. Retaining result documents from 24 years ago seems unnecessary and impractical. 3. With regard to NERC's PRC-005-2 Supplementary Reference Section 2.4 on Applicable Relays, E.ON U.S. offers the following comments: 3.1. This section extends the applicable relay coverage to IEEE type # 86 and IEEE type # 94. Some utilities define their turbine trip relay as an IEEE type #94. E.ON U.S. interprets that the NERC scope of applicable relays is that the turbine trip relays would be excluded; however, it would further clarify this exclusion if it were mentioned as an example in the last sentence. 3.2. The Tables in proposed standard PRC-005-2 require additional clarity. E.ON U.S. suggests renaming tables to 1, 2 and 3 to

Organization	Question 10 Comment
	match Level 1, 2 and 3 monitoring. The wording and format of text is not consistent between tables. 3.3. The fields in the tables are incoherent. E.ON U.S. interpretation is that intervals and activities for UFLS and UVLS are different than other relay systems and components, but this is unclear. E.ON U.S. believes a separate table or sections for UFLS and UVLS would provide more clarity. 4. In section 7 of the Supplementary Reference the SDT refers to the Bulk Power System instead of the Bulk Electric System. These are not interchangeable and the SDT needs to explain the need to use the term in this case. The phrase “support from protection equipment manufacturers” is used several times in the technical reference (Section 8 and Section 13) yet there is no manufacturer represented on the SDT. Rather than developing one size fits all requirements applicable to all equipment, E.ON U.S. suggests that the SDT pursue comments from manufacturers to obtain recommendations on what they believe is required to maintain and test their equipment.
Response: The SDT thanks you for your comments. **1. Although this SDT team (as an Interpretation Drafting Team) drafted the recent NERC interpretation of Protection System as it is applied to PRC-005-1, the SDT believes that the charger is an integral portion of the Station DC supply; thus it has been added to the definition of Protection System by replacing “station batteries” in the current definition of Protection System to “station dc supply” in the definition for the proposed standard (PRC-005-2). The SDT disagrees with your contention that testing of the station dc supply is necessary; the station dc supply is a critical component of the Protection System, and it must be verified that it can perform its required function.** **2. A single record is not adequate to demonstrate that the equipment has been maintained according to the intervals.** **3.1. The SDT revised the Supplementary Reference to remove references to IEEE function numbers except where they are critical to the discussion.** **3.2. The SDT believes that it is actually a single table with multiple sections and has retained the table numbering. The SDT has worked to improve the consistency between the table sections.** **3.3. The tables have been revised to clarify this area.** **4. The Supplementary Reference Document has been modified to use the NERC-defined term of “Bulk Electric System” or its defined abbreviation BES, rather than “Bulk Power System” or BPS. As for manufacturer input, the SDT is concerned that it would be a violation of NERC Anti-Trust rules to seek input from manufacturers.**	
Duke Energy	Regarding the Implementation Plan, 1. R1 compliance should be the first day of the first calendar quarter 18 months following applicable regulatory approvals. Entities will need this time to change monitoring equipment and develop extensive new work practices and procedures to assure time frames and documentation of practices comply with the wording of the revised standard. 2. The time frames for R2, R3 and R4 are adequate except in cases where upgrades have to be developed and implemented in

Organization	Question 10 Comment
	order to be able to meet the intervals (such as breaker trip coil verification every three months). 3. FAQ 2C "If I am unable to complete the maintenance as required due to a major natural disaster, how will this effect my compliance with the standard." Response is the Compliance monitor will consider extenuating circumstances? We would like to see this statement clarified as to the time frame extensions that result in non compliance or fines. 4. R4 States "each transmission owner" shall implement its PSPM, including identification of the resolution of all maintenance correctable issues. If the intent is to document resolution to misoperations this is a reasonable request. If the intent is to document that a relay was found out of calibration on a routine test, which was corrected by recalibration we need some clarity on expectations of how that would be recorded and tracked. As written this statement is vague and somewhat confusing since % of allowable error may vary utility to utility. R4 doesn't appear to allow any time beyond the stated intervals for repairs or replacements that may take additional time. PRC-005-2 is maintenance and testing standard, and R4 inappropriately requires a replacement strategy and an obsolescence strategy. Is R4 intended to apply to all equipment in Table 1?
Response: The SDT thanks you for your comments. **1. The SDT believes that time provided for R1 is sufficient. Additionally, entities can use the time required for NERC Board of Trustees and regulatory approvals to work on implementation.** **2. The SDT believes that the times provided for R2, R3, and R4 are adequate.** **3. The specific issues of how the Compliance Enforcement Authority would address this issue is outside the scope of the SDT. The response in the FAQ (FAQ IV-2-D, page 23) is extracted directly from the NERC Sanction Guidelines (effective January 15, 2008)** **4. The SDT has modified the standard to require initiation of the resolution of maintenance-correctable issues that cannot be resolved during the on-site maintenance; this is focused on assuring that the Protection System is capable of performing its desired function. R4 is intended to apply to ALL equipment in the PSMP.**	
Northeast Power Coordinating Council	1. Requirements 4.2.5.4 and 4.2.5.5 require clarification. It is recommended that the drafting team provide a schematic diagram to provide clarity as to which generator and system connected transformers are included in this facility identification. 2. When Measures are added to the Standard, the SDT must consider how the owner will be required to assess and document the decision of which table will apply to each protection. While this is a compliance element, the standard should provide clarity on this matter. As written, the requirement does not seem to be measurable. 3. Requirement R4 requires clarification on what is meant by "including identification of the resolution of all maintenance correctible issues as follows:" Correctible issues should not be combined in the same sentence with the layout of the tables. 4. Table 1b: In the section for "Protection system communication equipment and channels", there needs to be clarification on "verify that the performance of the channel and the quality of the channel meets the performance criteria, such as via measurement of signal level, reflected power, or data error rate." This may be done as a pass fail test during trip checks. If the

Organization	Question 10 Comment
	communication line successfully sends proper signals for the trip checks, then the communication line is acceptable and no additional measurement are taken. 5. Table 1c: There is some confusion on what is expected on items that have a Maximum Maintenance Interval reported as “Continuous”. For example, a component in the “Protection System telecommunication equipment and channels” how would one provide documentation or proof of the continuous verification of the two items listed in the maintenance activities” In other words how does one prove “Continuous verification of the communication equipment alarm system is provided” and “Continuous verification that the performance and the quality of the channel meet the performance criteria is provided”. These activities appear to be “monitoring attributes” more so than they are maintenance activities. 6. Additionally, the Continuous “Maximum Maintenance Interval” needs clarification because • the interval is a monitoring interval and not a maintenance interval • a strict interpretation of “Continuous” could require redundant monitoring systems be installed or locations staffed by personnel to monitor equipment in the event remote monitoring capabilities are unavailable • It is unclear how to provide proof to an auditor that continuous monitoring has occurred over a given interval? 7. Table 1a, 1b, and 1c: The maintenance activity for battery chargers are to perform testing of the charger at full rated current and verify current-limit performance. The drafting team should provide an industry standard as how to perform this check, or specify an industry equivalent test. 8. The Table 1b Level 2 Monitoring Attributes for Component “Monitoring and alarming of continuity of trip coil(s)” should be changed to read “Monitoring and alarming of continuity of all DC circuits including the trip coil(s)”. The present wording is confusing and can be interpreted to mean that the DC control circuitry needs to be checked every 12 years, as opposed to what we perceive to be the intended 6 years. 9. The Maintenance Activities in Table 1c are not consistent with the Level 3 Monitoring Attributes for Component “Protection system telecommunications equipment and channels.” 10. “Continuous verification of interface to protective relays” should be added as a third activity should be added under the Maintenance Activities column.” 11. In Section A. Introduction, 4.2.4 should be made to read “Protection System components which are installed as a Special Protection System for BES reliability. 12. For Requirement 4.1, a “grace period” similar to the NPCC criteria should be considered in case it is not possible to obtain any necessary outages to get the prescribed maintenance done. 13. Requirement R1 should be modified to read “Each Transmission Owner, Generator Owner, and Distribution Provider shall develop, document, and implement a Protection System Maintenance Program (PSMP) for its Protection Systems that use” This

Organization	Question 10 Comment
	revision reinforces what is necessary to ensure proper compliance with the program. 14. "The standard has multiple component tests required at different and conflicting intervals, some interdependent. Preference is to have the component listed with a common maintenance and testing interval assigned (list the testing required at 2, 4 and 6 years). This same interval should apply to all areas in the table." 15. Life span of PC's, software and software license's are much less than 12 years or asset life. This presents a problem during an audit where proof is required. The components in modern relays have not been proven over these extended time periods, users are dependent on proper functions of the alarm output of IED's. Prefer more frequent maintenance cycles over having to continuously document proof of a robust CBM or PBM program. 16. The burden placed to provide proof of compliance with a CBM or PBM maintenance program seems to outweigh any benefit in maintenance costs or reliability.

Response: The SDT thanks you for your comments.

1. Figure 2 in the Supplementary Reference Document (page 28) illustrates generator-connected and system-connected station service transformers. Additionally, 4.2.5.4 and 4.2.5.5 (in the Applicability section) further state, "for generators that are part of the BES", which must be taken in the context of the Regional Entity BES definition.

2. It is beyond the scope of a standard to require specific documentation; the entity must determine what documentation is necessary to clearly demonstrate that they are meeting the requirements. FAQ V-1-D, page 30 provides a discussion to assist in this determination.

3. The footnote for R4 has been modified to read as follows: A maintenance correctable issue is a failure of a device to operate within design parameters that can not be restored to functional order by repair or calibration while performing the initial on-site maintenance activity, and that requires follow-up corrective action.

4. A functional test only proves that the communication equipment is working. Table 1b requires that the performance criteria, such as signal levels, reflected power, etc are verified against the original performance criteria established when the channel was commissioned. See FAQ II-6-D, page 17.

5. For items with a maximum maintenance interval of "continuous", no activities are required, and the specified activities acknowledge that the monitoring of the component IS addressing the maintenance of the component.

6. The general information within the Table describes the attributes needed to achieve the Level 3 monitoring, and R2 requires that the entity establish a basis for the components to be addressed within Table 1c. Supplementary Reference Document, Sections 13 and 14 (page 20) provide discussion on this, and the Decision Trees in the FAQ and FAQ IV-1-A, page 21 also discuss this.

7. The SDT has modified the standard to remove this requirement in consideration of your comments.

8. The SDT has modified the standard to remove this requirement in consideration of your comments.

9. Table 1c has been modified to improve the consistency.

10. The SDT is not clear as to what you are suggesting.

Organization	Question 10 Comment
11. The SDT has modified the standard in consideration of your comment. As revised, 4.2.4 reads as follows: Protection System components installed as a Special Protection System for BES reliability. **12. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive.** **13. Documentation is a matter of demonstrating compliance, not of meeting the technical requirements of the Standard. R4 specifies the implementation of the PSMP.** **14. The testing specified for many components is different for the varying intervals; therefore, a separate table entry is present for each distinct interval. For the most part, the intervals are multiples of each other, (3-months, 18-months, 3-years, 6-years, and 12-years).** **15. Entities are certainly free to perform maintenance more frequently than specified in the standards.** **16. Entities do not have to adopt CBM or PBM; the entity must decide if the benefits of such programs justify the additional administrative effort.**	
Saskatchewan Power Corporation	1. Saskatchewan recommends that the PC's and RC's designate what equipment is applied to protect the BES and should be included in the protection maintenance program. It is questionable whether the facility owners or Distribution Providers will know. 2. What are the impacts on the BES from the protection systems identified in Facilities 4.2.5 and the FAQ? For example there is an impact on the BES from generator under-frequency protection not being properly coordinated, but assuming it is and if it is not maintained isn't the impact to the unit itself? Inadvertent energization protection also seems to be an impact to the unit itself not the BES? The standard should be concerned with protection systems that impact the BES not equipment protection that has localized impacts however important they may be. 3. Change Facilities 4.2.2 to "Protection System components used for under-frequency load-shedding systems which are installed to prevent system under-frequency collapse for BES reliability." The reference to ERO is unnecessary and inappropriate.
Response: The SDT thanks you for your comments. **1. The SDT disagrees. This standard applies to Protection Systems applied on, or that are designed to provide protection for the BES as defined by the Regional Entities.** **2. Fundamentally, if a system component is part of the BES, the protection on that component indeed affects the BES.** **3. The SDT believes that this Applicability is correctly stated in the standard. This directly reflects the current PRC-008-1 standard.**	
Detroit Edison	1. Suggest that the term "alarmed failures" in the table headings be changed to "alarmed abnormalities" to better indicate that the monitored parameter may be in an abnormal state or out of range but not necessarily failed. 2. Does "system-connected" station service transformers refer to transformers connected to the BES or transformers connected to

Organization	Question 10 Comment
	a system at any voltage level? 3. Is the intent of R1.1.2 that each Protection System component (specific relay at specific location) be listed individually with its associated maintenance method and interval or can the general component category be listed as such? 4. Regarding R4, further clarification would be helpful in understanding the intent of the term "resolution of all maintenance correctible issues" as it applies to R4.1 and R4.2. Is it intended that "maintenance correctible issues" be completed within the interval? 5. It is recommended that each line in the tables be given a number or letter designation to make reference to that row easier.
Response: The SDT thanks you for your comments. **1. The SDT understands your comment, and has elected to leave the terminology in the standard unchanged. While "failure" is not a defined term within the standard, the 11th Edition of Merriam Webster's Collegiate Dictionary includes, within the definition of failure, several relevant applications of this term, including "an omission of occurrence or performance", "a failing to perform a duty or expected action", "a state of inability to perform a normal function", and "an abrupt cessation or normal functioning".** **2. This phrase refers to generation plant station-service transformers connected at any voltage level, provided that the generator is part of the BES.** **3. This depends on the description of your program. You will need to describe your program in a way that will satisfy the requirements of the Standard.** **4. The SDT has modified the standard to require initiation of the resolution of maintenance-correctible issues, with no specific time-frame on completing the resolution.** **5. The SDT thanks you for your suggestion. This has been considered several times during the development of the tables, and several different arrangements attempted, and the SDT believes that the current presentation is the most effective way to present this complex material. The SDT will, however, continue to consider suggestions to improve this.**	
SERC (PCS)	The "zero tolerance" structure proposed combined with the large volume and complexity of Protection System components forces an entity to shorten their intervals well below maximum. We instead propose a calendar increment carryover period in which a small percentage of carryover components would be tracked and addressed. For example, up to 1% of an entity's communication channel 6 year verifications could carryover into the next year. These carryover components would be addressed with high priority in that next calendar increment. There are many barriers to 100% completion or zero tolerance. Some utilities have over ten thousand components.
Response: The SDT thanks you for your comments. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive.	

Organization	Question 10 Comment
Electric Market Policy	1. The "zero tolerance" structure proposed within this standard combined with the large volume and complexity of Protection System components requires a utilities processes and built-in grace periods to perform to perfection. Although this is a worthy goal for our industry, this can result in a large number of non-compliances for minor documentation issues or slightly missed maintenance schedules on an insignificant percentage of relays. The processing of these non-compliances can be costly in terms of resources that could be better utilized to address other transmission reliability matters. To provide a better approach, we suggest an incremental carryover system be permitted that would allow up to 0.5 percent of the PRC-005 maintenance task to be carried over to the next period, provided they are random events (not repetitive). As an example, a small percentage of our Protective System Control Trip tests on a 6-year interval could be carried over into the next calendar year when a generator outage is rescheduled. With this provision, these few tests could be handled without risk of a generator trip and without a compliance consequence. These carryover tasks could be addressed through an action plan with a defined completion date, and could be documented through a regional web portal. There are many barriers to 100% completion at a zero tolerance level with this volume of tasks.
Response: The SDT thanks you for your comments. The SDT is concerned that a "grace period", if permitted, would be used to establish a de-facto longer interval, and that the established intervals would thus not be measurable. Additionally, FERC Order 693 directed that NERC establish maximum maintenance intervals, and allowing for a "grace period" would not conform to this directive.	
Oncor Electric Delivery	1. The drafting team is to be commended for taking the Technical Paper and Draft Standard that was prepared by the NERC System Protection and Control Taskforce (SPCTF) and the recommendations of the SAR drafting team to create PRC-005-2. This draft standard allows the owners of Protection Systems several options in establishing a maintenance program tailored to their equipment and the topography of their system.
Response: The SDT thanks you for your support.	
US Bureau of Reclamation	The significance of this issue is not reflected in the period of time needed to review the documents. The supplement has many good ideas; however, the concept is going further than needed for establishing consistent maintenance intervals.
Response: The SDT thanks you for your comments. The NERC Standard Development Process normally allows for only 30-day or 45-day comment postings. The SDT intends to continue to use only the 45-day posting period of these in recognition of the extensive material to review.	
RRI Energy	1. The standard was written to implement generally accepted practices, but has developed requirements that are overly prescriptive relative to what will be required to demonstration compliance. The standard should not assume the need to write all aspects of a maintenance program into the standard or that maintenance programs will only consist of the standard requirements. Protection systems of the BES have and will continue to perform very reliably with the basic elements of a maintenance program without the need to divert resources for the development of excessive documentation to demonstrate compliance. PRC-005-1 is the most violated standard in the industry; not because of the lack of maintenance to protection systems, but because the

Organization	Question 10 Comment
	documentation requirements of the standard, given the large magnitude of components that fall within the scope of the standard. This standard significantly increases the administrative burden for additional documentation, without corresponding improvements to the reliability of the BES. 2. Recommend rewording A.4.2.5.1 as follows: "Generator Protection system components that trip the generator circuit breakers to separate and isolate the generator from the BES either directly in the breaker trip coil circuit or through interposing lockout or auxiliary tripping relays." This document should not expand the compliance scope beyond the definition of the BES. The generator protection systems that "trip the generator" also perform additional control functions that extend beyond the electrical isolation of the generating unit from the BES. These additional circuits do not protect the BES and do not belong in the scope of this document. 3. Recommend rewording A.4.2.5.4 as follows: "Protection systems for generator-connected station service transformers that trip the generator circuit breakers to separate and isolate the generator from the BES." This document should not expand the compliance scope beyond the definition of the BES. Related protection circuits of the transformer not involved with the electrical isolation of the generating unit from the BES does not belong in the scope of this document. 4. Recommend rewording A.4.2.5.5 as follows: "Protection systems for BES elements connecting to the station service transformers of generating stations." This document should not expand the compliance scope beyond the definition of the BES. The requirement incorporates radial feeds (with dedicated breakers) into the scope of the standard that are not necessarily a part of the BES as defined by some RRO's. Station service transformers are not necessarily required for generating unit operation. In some cases there are redundant sources for startup or back-up power. Protection of these transformers does not belong in the scope of the standard if they are not a part of the BES. 5. The suggested rewording of R1.2 is as follows: "Identify whether each Protection System component is addressed through time-based, condition-based, performance-based, or a combination of these maintenance methods." The requirement for the registered entity to list the interval of maintenance does not belong in the standard, especially since the maximum intervals are listed in the standard tables. The registered entity may have internal documents that intentionally target a shorter duration than the maximum interval of Table 1a. The failure to meeting those internally established targets can be a violation of the standard by the wording of this requirement. Allow R4 of the standard to identify the maximum allowable intervals. 6. In R4, the requirement for "identification of the resolution of all maintenance correctible issues" should be separated from the maintenance intervals; which define the maximum intervals of maintenance activities. The requirement should be eliminated to remove the overly prescriptive requirements of auditable documentation. If retained, a rewording of the requirement is as follows: "Each Transmission Owner, Generator Owner, and Distribution Provider shall identify the resolution of all issues identified and not corrected at the time the maintenance is initiated and the protected element is returned to service." The documented resolution of maintenance correctible issues (if retained) should apply only to activities that are unresolved and incomplete during the normal maintenance process. The standard should not micromanage the documentation process by creating requirements for excessive auditable records needed to demonstrate compliance of routine maintenance activities. 7. In R4, the requirements for Generator Owners which establish the durations of maximum allowable intervals should be

Organization	Question 10 Comment
	separated from the Transmission Owners, even if the intervals are the same. The reason is to allow for the assignment of different Violation Risk Factors. The Violation Risk Factor for the application of a 20 MVA generating unit with an operating capacity factor of less than 5%, and connected to a 138 kV system, should not be the same as those applied to a 500kV transmission line. The violation risks factors for these two applications are significantly different, and the ability to recognize this is not permitted by the standard presently. 8. Similarly, the criteria used for the sizing of station batteries for a large generating station is very different than those used for transmission facilities. Very little of the generating station battery sizing is related to BES protection, and nearly all generator protection system operations occur without reliance upon the battery. Without NERC standard requirements, Generator Owners have their own natural incentives to maintain batteries for the protection of the turbine generator bearings on the loss of AC power. With the most basic requirements of an inspection and maintenance program, there is an extremely high degree of reliability given the typical design of DC systems within a generating station, even without documented compliance to a rigid set of standards. With very basic, elementary maintenance (documented or not), the statistical probability for the random and simultaneous failure of multiple battery cells to disable the protection system of a generating station for the milliseconds of time required to separate a generating unit from the BES is insignificant (well in excess of 1 billion to 1 across an entire calendar quarter). 9. Violation risk factors and the resulting penalties for non-compliance need to be realistic.

Response: The SDT thanks you for your comments.

1. The SDT believes that the level of prescription within the standard is necessary to satisfy the guidance in FERC Order 693, and also to address observations from the Compliance Monitoring entities (the Regional Entities and NERC) that PRC-005-1 is excessively general. FERC Order 672 also specifies that NERC Reliability Standards should be clear and unambiguous. The SDT has therefore defined the minimum activities necessary to implement an effective PSMP.

2. The SDT believes that the standard is correct as drafted. Not only does the generator need to be disconnected, but this BES component must also be protected. Please refer to FAQ III-2-A, page 20 for a discussion of relevant Protection System components.

3. A loss of a generator-connected station auxiliary transformer will result in a loss of the generating plant if the plant is being provided with auxiliary power from that source.

4. A loss of a system-connected station auxiliary transformer could result in a loss of the generating plant if the plant was being provided with auxiliary power from that source, and this auxiliary transformer may directly affect the ability to start up the plant and to connect the plant to the system.

5. Inclusion of the intervals is necessary for PBM, and entities may elect to commit to more demanding intervals because of their experience.

6. The SDT has modified the standard to require initiation of the resolution of maintenance-correctible issues, but establishes no time line for the actual resolution, in recognition of the wide variation in the type of problems and the scale of the resolution.

7. The SDT disagrees. It the protection on the cited 20 MVA generating unit fails to properly isolate the unit from the system for fault conditions, it could have serious effects on reliability.

Organization	Question 10 Comment
8. The SDT believes that the station dc supply is such an integral part of the Protection System of a generating station that, it falls under NERC Reliability Standard purview and at a minimum must be maintained using the Maintenance Activities and Maximum Maintenance Intervals of Table 1. **9. The SDT will consider this with developing VRFs and VSLs.**	
Lower Colorado River Authority	We commend the work done by the SDTSDT. In particular, the merging of previous standards PRC-005-0, PRC-008-0, PRC-011-0, and PRC-017-0 which will help with the efficient management of these standards.
Response: The SDT thanks you for your support.	
Ontario Power Generation	We note that Verification of Voltage and Current Sensing Device Inputs to Protective Relays is a somewhat ambiguous activity. NERC's audit observation team came up with a similar finding. The supporting documents provide some clarity but in our opinion it would be helpful if the SDT could elaborate this activity in more detail in the Table itself.
Response: The SDT thanks you for your comments. The Tables have been modified to clarify this issue.	
Southern Company	1. We presently utilize a UFLS system distributed across many transmission and distribution substations. Are the station batteries located in stations with no network transmission protection schemes (other than UFLS) subject to the requirements of PRC-005-2? This was not addressed in previous revisions. 2. We presently utilize a UVLS system distributed across many transmission and distribution substations. Are the station batteries located in stations with no network transmission protection schemes (other than UVLS) subject to the requirements of PRC-005-2? 3. In the applicability section, there is no exception for smaller units and those with very low capacity factors. Rather, those that "are part of the BES" are in the scope. We recommend that smaller units and low capacity factor units be exempt from the requirements of this standard or have extended maintenance intervals. Refer to the current SERC supplement for PRC-005-1. Section II.A. of the May 29, 2008: SERC Supplement Maintenance & Testing Protection Systems (Transmission, Generation, UFLS, UVLS, & SPS) NERC Reliability Standards PRC-005-1, PRC-008, PRC-011, & PRC-017.The applicability section paragraph 4.2.4 should read "are installed" rather than "is installed". 4. Note 2 at the bottom of the table (1c) implies that one has to apply voltage and inject current into the microprocessor relay to perform trip checks. Is this the intent of the statement? If so, Note 2 should be revised to make clear the intention. We don't think this is necessary with microprocessor relays since they monitor inputs 5. Why is the Violation Severity Level Matrix not a part of this standard revision? 6. In cases where a common dc system exists between a generator owner and transmission owner, who is the responsible entity? 7. We appreciate the work that went into the implementation plan. We agree with the concept of phasing in mandatory compliance

Organization	Question 10 Comment
	and the timing of the implementation. 8. Consider defining the Monitoring Levels once and reformatting the information contained within Tables 1a, 1b, and 1c to regroup the information by component type rather than by Monitor Level. When considering the various monitoring levels for the protection system components, each entity will consider each component type apart from the others when determining the Monitor Level to apply, so this reorganization will assist the end user to understand and apply the levels. See samples attached as a separate document:
Response: The SDT thanks you for your comments. **1. The SDT has modified the standard to clarify that the only DC Supply requirement relevant to UVLS and UFLS is to verify the DC supply voltage, and that this may be performed in conjunction with the UFLS/UVLS maintenance itself.** **2. The SDT has modified the standard to clarify that the only DC Supply requirement relevant to UVLS and UFLS is to verify the DC supply voltage, and that this may be performed in conjunction with the UFLS/UVLS maintenance itself.** **3. This is properly a NERC registration issue and one of the regional BES definitions. We appreciate that you may disagree with these, but you should seek resolution via other means. The SDT has modified the standard in consideration of your editorial concern. It the protection on a small generating unit fails to properly isolate the unit from the system for fault conditions, it could have serious effects on reliability.** **4. Note 2 has been removed from the Table.** **5. Even though the SDT worked on a VSL matrix during development of this draft, the SDT elected to constrain this posting only to the requirements and supporting developments. The SDT believes that this was such an extensive body of material that it would be distracting to include compliance elements. The SDT also recognized that extensive changes were likely to occur to the standard in response to this posting, and considered this in their decision to not include compliance elements. They will be included in the next posting.** **6. The SDT believes that the owner of the battery is responsible. This can be worked out by agreements between the entities.** **7. The SDT thanks you for your support.** **8. The SDT has experimented with various arrangements of the Tables with some input from external parties, and believes that the presentation shown in the standard is the best way to present this complex information. The SDT has attempted to make the arrangement of the three tables as similar as possible to address your concern.**	
PacifiCorp	What is the definition of "Calendar Year"? Does the term "Six calendar years" include any date in 2004 to any date in 2010?
Response: The SDT thanks you for your comments. Disregard the complete date and just look at the year portion. For a 6 calendar-year interval, if the test date was IN 2004, the next test must be completed by the end of 2010.	

Organization	Question 10 Comment
AECI	
Puget Sound Energy	Great improvement in the standards and clarity of expectations. We appreciate the combining of the multiple PRC standards. PSE would appreciate the comments and clarification needed regarding the interpretation for PRC-005 under Project 2009-17 to be included in PRC-005-2. It appears that the interpretation allowed regions to define variances due to the variance in the Regional Entity definitions of the BES. But how the BES is defined and documented as such creates ongoing confusion for the registered entities.
Response: The SDT thanks you for your comments. The NERC definition for BES specifically includes, "As specified by the regions". As long as this definition persists, the issue noted in your comments will also persist. It is outside the scope of this standard to address these issues.	