Individual or group. (55 Responses)
Name (33 Responses)
Organization (33 Responses)
Group Name (22 Responses)
Lead Contact (22 Responses)
Question 1 (47 Responses)
Question 1 Comments (55 Responses)
Question 2 (45 Responses)
Question 2 Comments (55 Responses)
Question 3 (38 Responses)
Question 3 Comments (55 Responses)
Question 4 (40 Responses)
Question 4 Comments (55 Responses)
Question 5 (0 Responses)
Question 5 Comments (55 Responses)

Individual
Robert W. Kenyon
NERC - EA & I
Recommend entities be explictly required to document the Relay Maintenance Program in one document. Many entities presently maintain their Protection Maintenace Program in several documents, such as one for relays, one for batteries, etc. This complicates compliance review and contributes to non-compliance since personnel in diffeernt departments writing these have different levels of understanding of NERC standards. Separate documents also allow inconsistencies to slip in. Recommend Requirement 1 to changed to the following to address this problem. "Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP), RECORDED AND UPDATED AS A SINGLE DOCUMNET for its Protection Systems designed to provide protection for BES Element(s). "
Individual
Daniel Duff
Liberty Electric Power LLC
Yes
Yes
No
See comments at end.
Apologies to the drafting team for submitting this with the ballot, repeated here to insure the comments are captured and addressed. While the SDT has done a very good job at responding to the most objectionable parts of the previous version, there are still a number of issues which makes the standard problematic. 1. The standard introduces the term "initiate resolution". This is an interpretable term, and has the potential for an auditor and an entity to disagree on an action. Would issuing a work order be considered "initiating resolution"? What if the WO had a completion date many years into the future? I would suggest adding the term to the list of definitions which will remain with the standard, and defining it as "preforming any task associated with conducting maintenance activities, including but not limited to issuing purchase orders, soliciting bids, scheduling tasks, issuing work requests, and performing studies". 2. Some clarity is needed to differentiate system connected and generator connected station service transformers. A statement that a station

service transformer connected radially to the generator bus is considered a system connected transformer if the transformer cannot be used for service unless connected to the BES. 3. The "bookends" issue, brought up in the prior round of comments, still exists. Although the SDT rightly notes a CAN has been issued regarding bookends, the CAN covers the documentation for system components that entities were required to self-certify to on June 18, 2007. PRC-005-2 adds additional components to the protection system scheme which were not part of that certification, and has the potential to put entities into violation space due to a lack of records for those components. The SDT should add to M3 a statement that entities may demonstrate compliance with the standard by demonstrating that required activities took place twice within the maximum maintenance interval - starting from the effective date of the standard - for all components not listed in PRC-005-1.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
Yes
Yes
Suggest that to FAQ be added: 1. Regarding Table 2 in the standard, does a fail-safe “form b” contact that is alarmed to a 24/7 operation center qualify as an alarm path with monitoring? 2. Add a clarification as part of the FAQ document that defines whether the control circuitry and trip coil of a non-BES breaker, tripped via a BES protection component, must be tested as per Table 1.5.
Group
MISO Standards Collaborators
Marie Knox
Yes
Yes, however, in the “Supplemental reference and FAQ” document on page 65 there are two areas of concern. Page 65, paragraph 4: “… the type of test equipment used to establish the baseline must be used for any future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer’s equipment.” While we understand the importance of creating a baseline, it is not feasible to expect the test equipment be the same as the manufacturer’s test equipment or even the same test equipment over the life of the battery. The expected life of a battery may be in excess of 20 years and it is not feasible to expect that the type of equipment will not change during this period. On Page 65, paragraph 6, it states: “… all manufacturers of internal ohmic measurement devices have established libraries of baseline values …” We question the availability of baseline libraries for all manufacturers considering the variety and longevity of installations.
Yes
Yes
Yes
The additional documentation seems to be quite large, and the additional content seems to go far beyond what is necessary for the PRC-005-2 standard. We recommend the SDT lessen the amount of content provided in the “Supplementary Reference” document.
R3 speaks of a Maintenance Correctable Issue and implementing your Protection System Maintenance Program (PSMP). In the definition of Maintenance Correctable Issue, it states "...of the initial on-site activity". The intent seems to be that during any maintenance activity, and something is found not working properly, you should repair it. Some may look at the word "initial" as during the commissioning of a facility. We recommend the SDT delete the word "initial" to cause less confusion.

We recommend the SDT change the text of “Standard PRC-005-2 – Protection System Maintenance” Table 1-5 on page 19, Row 1, Column 3 to “Verify that each a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.” Or alternately, “Electrically operate each interrupting device every 6 years”. Trip coils are designed to be energized no longer than the breaker opening time (3-5 cycles). They are robust devices that will successfully operate the breaker for 5,000-10,000 electrical operations. The most likely source of trip coil failure is the breaker operating mechanism binding, thereby preventing the breaker auxiliary stack from opening and keeping the trip coil energized for too long of a time period. Therefore, trip coil failure is a function of the breaker mechanism failure. Exercising the breakers and circuit switchers is an excellent practice. We would encourage language that would suggest this task be done every 2 years, not to exceed 3 years. Exercising the interrupting devices would help eliminate mechanism binding, reducing the chance that the trip coils are energized too long. The language as currently written in Table 1-5, Row 1, will also have the unintentional effect of changing an entities existing interrupting device maintenance interval (essentially driving interrupting device testing to a less than 6 year cycle). We recommend the SDT change the text of “Standard PRC-005-2 – Protection System Maintenance” Table 1-5 on page 19, Row 3, Column 2 to “12 calendar years”. The maximum maintenance interval for “Electromechanical lockout and/or tripping devices which are directly in a trip path from the protective relay to the interrupting device trip coil” should be consistent with the “Unmonitored control circuit” interval which is 12 calendar years. In order to test the lockout relays, it may be necessary to take a bus outage (due to lack of redundancy and associated stability issues with delayed clearing). Increasing the frequency of bus outages (with associated lines or transformers) will also increase the amount of time that the BES is in a less intact system configuration. Increasing the time the BES is in a less intact system configuration also increases the probability of a low frequency, high impact event occurring. Therefore, the Maximum Maintenance Interval should be 12 years for lockout relays. We recognize the substantial efforts and improvements to PRC-005-2 that have been made and appreciate the dedicated work of the SDT. We appreciate the removal of Requirement R1.5 and R4 and other clarifications from draft 3. Our remaining concern for PRC-005-2 is with definition and timelines established in Table 1-5. We believe that, as written, the testing of “each” trip coil and the proposed maintenance interval for lockout testing will result in the increased amount of time that the BES is in a less intact system configuration. We hope that the SDT will consider these changes.
Group
Electric Market Policy
Mike Garton
Yes
Yes
No
IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months must implement a policy of two months with one month of grace period thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, Dominion suggests that all battery maintenance intervals expressed as 3 calendar months be changed to 4 calendar months.
Group
Luminant
David Youngblood
Yes
No comments.
Yes
No comments.

Yes
No comments.
Yes
The document was valuable in understanding PRC-005-2 by providing clarification using practical protective relay system examples. Below are two comments for further improvement. 1. It would be beneficial if the document could provide additional information for relaying in the high-voltage switchyard (transmission owned) - power plant (generation owned) interface. While Figures 1 and 2 are typical generation and transmission relay diagrams, it would be helpful if protective relays typically used in the interface also be included. For example, a transmission bus differential would remove a generator from service by tripping the generator lockout. 2. Figures 1 and 2 refer to a “Figure 1 and 2 Legend” table which provides additional information on qualifications for relay components. Should a footnote be used to point toward Reference 1 (Protective System Maintenance: A Technical Reference) located in Section 16?
The red-lined version did not appear to agree with the clean copy. In reading the "red lined" document it appears that R3 was intended to be "Each Transmission Owner, Generation Owner, and distribution Provider shall implement and follow its PSPM and initiate resolution of any identified maintenance correctable issues."
Individual
Russ Schneider
FHEC
Yes
No
Can't locate the implementation plan in the posted materials.
No
For Distribution Provider level equiment there should be no High or Severe VSLs
Yes
It is unclear what compliance obiligations may be created or clarified with the FAQ. It is a good explanatory document and a helpful reference, but the Standard should speak for itself as it relates to what it takes to achieve compliance.
Individual
Michelle D'Antuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration, LP, continues to believe that the six year requirement to verify channel performance on associated communications equipment will prove to be more detrimental than beneficial on older relays. Clearly newer technology relays which provide read-outs of signal level or data-error rates will easily verified, but the tools which measure power levels and error rates on non-monitored communication links are far more intrusive. After the technician uncouples and re-attaches a fiber optic connection, the communications channel may be left in worse shape after verification than it was prior to the start of the test. However, we have found that the remainder of the items in the Tables are logically organized and correspond effectively with the five components of a Protection System. The maintenance activities and intervals are technically solid and reasonable. In our opinion, the benefits to proceed outweigh our one concern with the validation of communications channel performance.
Yes
Yes
No

The removal of R1.5 and R7 which required Protection System owners to identify and verify calibration tolerances or equivalent parameters upon conclusion of a maintenance activity was fundamental to Ingleside Cogeneration's "yes" vote. The amount of ambiguity introduced by the requirements and associated documentation did not serve to improve BES reliability in our view.
Group
Santee Cooper
Terry L. Blackwell
Yes
Yes
Yes
No
Comments: Santee Cooper does not agree with the expansion of the UFLS and UVLS requirements to include the dc supply. We understand that, in the previous consideration of comments, it is stated that "For UFLS and UVLS, the maintenance activities related to station dc supply and control circuitry are somewhat constrained relative to similar activities for Protection Systems in general." In the table, the requirement for dc supply for UFLS is to verify the station dc supply voltage when the control circuits are verified, which could be 6 or 12 years. It seems like the restraint shown in the requirement, if an indication of the level of need for the verification, is of a much longer timeframe than what would actually happen in the typical operation of a distribution system. Therefore, proof of this verification seems to be of minimal value compared to the extra documentation required due to this now being an auditable maintenance activity. We also agree that maintenance activities with fast intervals, especially the 3 month ones, should be adjusted to 4 months to allow for the actual interval the entities use to be 3 months. Having the requirement at 3 months forces the utilities to schedule even faster (such as every month or 2 months) to ensure compliance.
Individual
Beth Young
Tampa Electric Company
No
If during a UF operation there were ever any breakers that did not trip properly, there may be enough that do trip to return things to balance. There is more room for error with UFLS than with BES. The standard does make some allowance for differences between UFLS equipment and BES equipment. For example the DC source testing requirement for UFLS is to just test the battery voltage when the control circuit is tested. It is not necessary that the breaker be tripped for UFLS testing every six years as is the case for BES. However, every 12 years all unmonitored control circuitry must be tested, which may include tripping the breaker.
No
The new maintenance plan has to be completed in 1 year. Would that mean it is required to identify and list every element that requires testing in a database within the first year. This will be a time intensive effort that probably that would be difficult to complete in a year with current personnel. After 1 year, would entities be required to start implementing the plan depending on the maintenance intervals of the equipment. Qualified people would have to be in place to start the work, again this would be difficult to accomplish with current personnel.
No
VSL is severe for more than 4% Countable Events on R2. It does not seem feasible.
No
Tampa Electric requests further differentiation between BES protection elements and UFLS equipment.
As written PRC-005-2 would have a very significant impact on Tampa Electric Company with very little reliability benefit. For the testing of the DC control circuits Tampa Electric would need to remove from

service each BES element (circuit, bus, transformer, breaker) and perform an R&C checkout somewhat equivalent to what Tampa Electric does for new construction. That process would have to be repeated no less often than every six years. The testing of DC control circuits to the level described / required in the proposed standard in an energized station is a very risky proposition. Even though an element can be taken out of service for testing, the DC control circuits are often interconnected for functions such as breaker failure, bus and transformer lockouts etc. It is very easy to accidentally trip other in service equipment while doing this testing. Another concern is getting outages on equipment to perform the proposed testing. Tampa Electric believes that there is an unnecessary expansion of the scope of equipment covered by the proposed PRC-005-2 standard into the distribution system related to UVLS and UFLS. Currently, PRC-005-1 includes batteries, instrument transformers, DC control circuitry and communications in addition to the relays for BES protection systems. PRC-008 (UFLS) and PRC-011 (UVLS) are ambiguous as to whether non-relay components are included in those standards. The proposed PRC-005-2 includes the non-relay components into UFLS and UVLS. The problem is, for UFLS and UVLS, the non-relay components are mostly distribution class equipment; hence, the result of this version 2 standard will be inclusion of most distribution class protection system components into PRC-005-2. This is a huge expansion of the scope of equipment covered by the proposed standard with negligible benefit to BES reliability. In addition, testing of protection systems on distribution circuits is difficult for distribution circuits that are radial in nature. In addition, non-relay protection components operate much more frequently on distribution circuits than on transmission Facilities due to more frequent failures due to trees, animals, lightning, traffic accidents, etc., and have much less of a need for testing since they are operationally tested. As another comment, station service transformers are not BES Elements and should not be part of the Applicability - they are radial serving only load. Tampa Electric's Energy Supply Department has the following comment / question regarding Data Retention: • For Requirement R3 R2 and Requirement R4R3, the Transmission Owner, Generator Owner, and Distribution Provider shall each keep documentation of the two most recent performances of each distinct maintenance activity for the Protection System components, or all performances of each distinct maintenance activity for the Protection System component since or to the previous scheduled audit date, whichever is longer. If all of the data which the proposed PRC-005-2 standard requires to be collected is not be available or kept for the prescribed period of time, how does a registered entity comply with the required data retention?
Group
Bonneville Power Administration
Denise Koehn
Yes
No
Many of the maintenance intervals in the standard are given in the terms calendar years or calendar months. There is no description of these terms in the NERC Glossary. My Webster's dictionary defines calendar year as the period that begins on January 1 and ends on December 31. There is no definition in my dictionary of calendar month. Is the intent of the term calendar year in the standard that maintenance intervals start on January 1 and end on December 31? This would make all maintenance due on December 31, and December would be a very busy time. Does this mean that if I do maintenance on something with a maximum interval of six calendar years in June of 2011 that it will be due again on January 1 of 2017 instead of June 1 of 2017? We believe that the drafting team intends for maintenance to be due after a given number of years that begins to elapse immediately after the previous maintenance is completed so that in the previous example the maintenance would be due on June 1, 2017. Please remove the word calendar from the maximum maintenance intervals to remove this confusion.
In the header of Tables 1-1, 1-2, 1-3, and 1-5 there is a note that says "Table requirements apply to all components of Protection Systems except as noted." Since each table only applies to the specific component type shown in the header, we do not understand what this note means. The definition given for component only makes the note more confusing. Please clarify the note. Additionally, BPA is voting no during this round due to an issue with the Applicability Section and Section 4.2. Once this

issue is clarified, BPA would be in support of a yes vote. Issue: Section 4.2 Facilities lists 5 separate items that the standard is applicable for (4.2.1. – 4.2.5). However Requirement 1 uses language that only addresses one of the items (4.2.1). There is no language contained anywhere within any of the requirements in PRC-005-2 that apply to the types of protection systems described in Applicability Sections 4.2.2 – 4.2.5. Therefore, it could be argued that this leaves it open to interpretation as to whether UFLS/UVLS/SPS are addressed by R1. In the NOPR (¶ 105), FERC states that “the Requirements within a standard define what an entity must do to be compliant”. Further, in Order 693 (¶ 253) FERC explicitly states that “compliance will in all cases be measured by determining whether a party met or failed to meet the Requirement”. Given this, then from a compliance perspective, the actual applicability of the standard appears to not be as broad as intended. We ask that this issue be resolved by modifying the language in R1 in a manner that explicitly encompasses all types of protection systems to which it is intended to be applied.
Group
Progress Energy
Jim Eckelkamp
Comments on Draft Standard 1. Table 1-1, 2nd row, 2nd bullet: The comment “(see Table 2)” does not apply to this bullet, but applies to the first bullet. 2. Table 1-3, 2nd row: Need to add “(See Table 2).” Comments on Implementation Plan 1. Section 3a states that “The entity shall be at least 30% compliant on the first day of the first calendar quarter 2 calendar years following applicable regulatory approval…” If regulatory approval occurs on January 31, 2012, does this mean that the entity has until December 31, 2014 to be 30% compliant? It might be beneficial to provide an example explaining “calendar year.” Comments on Supplementary Reference 1. Table of Contents does not list Section 15.4 2. Page 54, last paragraph, last sentence: “…advances that are may be coming…” 3. Page 65, 5th paragraph: VLRA should be VRLA 4. Page 67, 4th paragraph, 4th sentence: “…typically looking for on the plates…” 5. Page 69, 4th paragraph, last sentence: “…Grounds because to of the possible…” 6. Page 69, 5th paragraph, 2nd sentence: “For example, to do I need…” 7. Page 70 5th paragraph, 5th sentence: “A manufacturer of…” 8. Page 70 5th paragraph, 6th sentence: “…by a third manufacturer’s equipment…” 9. Page 71, first line: “…(impedance, conductance, and resistance)…”
Group
SPP reliability standard development Team
Jonathan Hayes
Yes
Yes
No
If the maintenance is done prior to the maximum interval would it then reset the clock. Or should it read that maintenance and testing should be done at least once per quarter etc. We would like to see the plan split up into generation time horizons and transmission time horizons, these can be significantly different.
No
Would like more clarification in table 1-5 to address verification tests on different circuits. Is this an end to end test or partial test can you test one part of the circuit one way and another a different way? Should table 1-5 read Complete a terminal test of unmonitored circuitry?
Group
Western Electricity Coordinating Council
Steve Rueckert

No
The proposed PRC-005-2 standard is an improvement over the four standards that it will replace. However, section 4.2 identifies five types of protection systems that the standard is applicable to, but the language of Requirement 1 indicates that applicable entities need to establish a Protection System Maintenance Program (PSMP) for the Protection Systems designed to provide protection for BES Element(s) (Part 4.2.1 of Section 4.2). We believe the intent is to have a PSMP for all Protection Systems identified in Section 4.2 and that the language of Requirement 1 may cause confusion or be misleading. We suggest changing the language of Requirement 1 from: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems designed to provide protection for BES Element(s). to: Each Transmission Owner, Generator Owner, and Distribution Provider shall establish a Protection System Maintenance Program (PSMP) for its Protection Systems identified in Section 4.2.
Group
Pepco Holdings Inc
David Thorne
Yes
Yes
No
1. Are the bullet items listed for the R2 Severe Violation Severity Level , Item 5 an "and" or an "or"? 5) Failed to: • Annually update the list of components, • Perform maintenance on the greater of 5% of the segment population or 3 components, • Annually analyze the program activities and results for each segment. 2. The wording of the R3 Lower Violation Severity Level seems to imply that an entity that fails to complete 0% (i.e., completes 100%) of its maintenance correctable issues is non-compliant. Entity has failed to complete scheduled program on 5% or less of total Protection System components. OR Entity has failed to initiate resolution on 5% or less of identified maintenance correctable issues. The following re-phrasing is suggested: Entity has failed to complete scheduled program on greater than 0%, but no more than 5% of total Protection System components. OR Entity has failed to initiate resolution on greater than 0%, but less than or equal to 5% of identified maintenance correctable issues.
Yes
The Supplementary Reference and FAQ should be an attachment to the standard (Appendix A)and not just referenced. If not attached it will not be readily accessible to those that will be using the standard.
There were numerous comments submitted for each of the previous drafts indicating that the 3 month interval for verifying unmonitored communication systems was much too short. The SDT declined to change the interval and in their response stated: "The 3 month intervals are for unmonitored equipment and are based on experience of the relaying industry represented by the SDT, the SPCTF and review of IEEE PSRC work. Relay communications using power line carrier or leased audio tone circuits are prone to channel failures and are proven to be less reliable than protective relays." Statistics on the causes of BES protective system misoperations, however, do not support this assertion. The PJM Relay Subcommittee has been tracking 230kV and above protective system misoperations on the PJM system for many years. For the six year period from 2002 to 2007, the number of protective system misoperations due to communication system problems was lower (and in many cases significantly lower) than those caused by defective relays, in every year but one. Similarly, RFC has conducted an analysis of BES protection system misoperations for 2008 and 2009, and found the number of misoperations caused by communication system problems to be in line with the number attributed to relay related problems. If unmonitored protective relays have a 6 year maximum maintenance/inspection interval, it does not seem reasonable to require the associated communication system to be inspected 24 times more frequently, particularly when relay failures are statistically more likely to cause protective system misoperations. As such, a 12 or 18 calendar month

interval for inspection of unmonitored communication systems would seem to be more appropriate. FAQ II 6 B states that the concept should be that the entity verify that the communication equipment...is operable through a cursory inspection and site visit. However, unlike FSK schemes where channel integrity can easily be verified by the presence of a guard signal, ON-OFF carrier schemes would require a check-back or loop-back test be initiated to verify channel integrity. If the carrier set was not equipped with this feature, verification would require personnel to be dispatched to each terminal to perform these manual checks. The SDT responded that they still felt the 3 month interval as stated in the standard was appropriate. PHI respectfully requests that the SDT reconsider this issue and also cite what "specific statistical data" they used to validate that unmonitored communication systems are 24 times more prone to failure than unmonitored protective relays.
Individual
Joe O'Brien
NIPSCO
Yes
Sub-tables are good. A related question: Some devices such as reclosers and circuit breakers may include batteries within the device itself. Does Table 1-4 apply to such batteries and DC supply? Recloser batteries do not provide access to intercell connections.
No
This new standard's calibration intervals outlined here will require additional staff at our organization. In order to get people hired and trained the implementation plan should allow more time for the phase-in period. From experience, calibration should have been de-emphasized since more concerns are discovered during full tests.
no comments at this time
Yes
We used the FAQ Supplemental Reference while reviewing this draft standard and found it useful.
The present PRC-005 standard is 2 pages while the proposed PRC-005-2 is 22 pages, with an implementation plan of 4 pages and a supplemental document of 87 pages. The review process appears to be somewhat daunting especially considering that NERC is trying to simply things with such concepts as the "traffic ticket" approach. In R3 we're not sure if there is a time requirement regarding the completion of the resolution process. We like the use of "calendar year" in requirements which should provide flexibility in getting the work completed. Another comment for our response concerns Table 1-2, Communications Systems (page 11): The first maintenance interval is 3 calendar months. Does this mean the same as 1 calendar quarter? 1. Example for 3 calendar months:Maintenance performed on 1/4/11. Next maint due by 4/30/11. Maintenance performed on 4/12/11. Next maint due by 7/31/11. Maintenance performed on 7/30/11. Next maint due by 10/31/11. This would yield 3 inspections for 2011. Maintenance performed on 10/12/11. Next maint due by 1/31/12. 2. Example for 1 calendar quarter: Maintenance performed on 1/4/11. Next maint due by 6/30/11. This would yield 4 inspections for 2011 (1 per quarter).
Individual
Linda Jacobson
Farmington Electric Utility System
Yes
Yes
No
VSL on R2: Lower criteria item 1; the wording is identical High VSL. FEUS recommends keeping the criteria in the Lower VSL.
No
Individual
Greg Rowland

Duke Energy
Yes
We believe the table could be improved further to aid compliance by adding a footnote to the term “baseline” in the sub-tables 1-4(a), 1-4(b) and 1-4(f). The following proposed footnote text is taken from page 65 of the Supplementary and FAQ Reference Document: “Often for older VLRA batteries the owners of the station batteries have not established a baseline at installation. Also for owners of VLA batteries who want to establish a maintenance activity which requires trending of measured ohmic values to a baseline, there was typically no baseline established at installation of the station battery to trend to. To resolve the problem of the unavailability of baseline internal ohmic measurements for the individual cell/unit of a station battery, all manufacturers of internal ohmic measurement devices have established libraries of baseline values for VRLA and VLA batteries using their testing device. Also several of the battery manufacturers have libraries of baselines for their products that can be used to trend to.”
Yes
No
Typographical error - the High VSL for R2 has been incorrectly changed to “within three years” from “within four years”. This is now the same as the Lower VSL.
Yes
Along the lines of what we have suggested in our comment to Question #1 above, we believe it would make compliance more certain if selected language from the Supplementary reference could be incorporated into the standard, either directly in requirements, or in footnotes.
The Standard Drafting Team has done an outstanding job on this standard. We are voting “Affirmative” but note that implementation questions remain, particularly with regards to classifying component attributes as “monitored”, “unmonitored”, “internal self diagnosis”, “alarming”, “alarming for excessive error”, and “alarming for excessive performance degradation”. The sheer size of the population of protective relays, communications systems, voltage and current sensing devices, batteries, and dc supply components means that the size of the effort required to categorize each individual component could drive us to test and maintain on the more frequent unmonitored time intervals, simply because of the difficulty in assembling “monitored” compliance documentation.
Individual
Steve Alexanderson
Central Lincoln
Yes
Yes
Yes
No
The first FAQ under 2.3.1 is incorrect, referencing a FERC informational filing. Included in the filing was a WECC test that was never approved by the WECC board and is not being used. Using this document as suggested will get WECC entities into trouble.
As we stated two ballots ago, we continue to believe that IEEE battery standard quarterly maintenance was never intended to be performed at a maximum interval of three months. Instead, three months is a target value that might be extended due to emergency. We continue to support a maximum interval of four months for these activities.
Individual
Bob Thomas
Illinois Municipal Electric Agency
Yes
Yes

No
The scope of the equipment to which the draft standard applies is still overly broad. Specifically, PRC-005-2 should not apply to non-relay equipment for UFLS and UVLS systems. Subjecting UFLS and UVLS batteries, instrument transformers, DC control circuitry, and communications to the requirements of PRC-005-2 would drastically increase the scope of equipment covered by the standard, with no corresponding benefit to reliabiltiy of the BES. This comment/recommendation is provided to address the resource and customer service interests of a TO and/or DP systems serving distribution load. Illinois Municipal Electric Agency supports comments submitted by the Transmission Access Policy Study Group.
Individual
Joe Petaski
Manitoba Hydro
Yes
The restructured tables are an improvement, but we suggest that conductance (siemens) should be listed as an acceptable measurement in addition to the resistance measurements already included in the tables.
Yes
No
VSL for Requirement 2: -Needs to use consistent terminology. The standard requirements refer to components and component types, not elements. -The violation “Entity has Protection System elements in a performance-based PSMP but has failed to reduce countable events to less than 4% within three years” appears in both the Lower VSL column and the High VSL column. The violation cannot be both Lower and High. VSL for Requirement R3: -Suggested wording “completed its scheduled program”.
A red line was not provided making this document difficult to review. We suggest that a redline of this document be posted.
-Grace periods Grace periods should be permitted on the maintenance time intervals. While we understand that grace periods can be built into a PSMP, maintenance decisions that compromise reliability may still have to be made just to meet the specified time intervals and avoid penalty. An example of this would be removing a hydraulic generator from service at a time of low reserve to meet a maintenance interval and avoid non-compliance (removing an asset in a time of constraint). Grace periods are also required in the case of extreme weather conditions. Such conditions may make it unsafe to perform maintenance within the maintenance interval or may create a risk to reliability if the equipment being maintained is removed from service during these conditions. Utilities need to retain a reasonable amount of discretion and flexibility to make maintenance decisions that are best for reliability without risking non-compliance. -Battery Check Interval Manitoba Hydro maintains our position that the 3 month battery check interval should be extended to 6 months. The 3 month interval is too frequent based on our experience and while IEEE std 450 (which seems to be the basis for table 1-4) does recommend intervals, it also states that users should evaluate these recommendations against their own operating experience. With the 3 month battery check frequency and no allowance for a grace period, there may be a negative impact on reliability caused by diverting resources away from projects that are critical to reliability to meet this maintenance interval.
Individual
Mike Hancock
Shermco Industries
Yes
Yes

Yes
No
Please provide clarification on "Communications" in regards to the following: If our customers are utilizing Schweitzer SEL311 relays and utilizing the fiber for transfer trip, is this considered a communications circuit? Our experiences in regards to testing these devices that have transfer trips out into a main substation, that could affect a main ring tie or open a major 138kV loop, are that the T&D utilities will not allow us to perform these tests and trip their breakers. Therefore, what is required to satisfy testing? In regards to Function / Trip testing, if we have a sudden pressure device, this is considered an auxiliary relay and the sudden pressure relay itself is not required to be tested. However, the trip path is required to be tested for DC tripping, if it directly trips the breaker feeding the BES, on the DC Control verification testing. Please clarify if this is correct.
Individual
Michael Crowley
Dominion Virginia Power
Yes
Yes
No
Comments: IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months must implement a policy of two months with one month of grace period thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, Dominion suggests that all battery maintenance intervals expressed as 3 calendar months be changed to 4 calendar months.
Individual
Edward J Davis
Entergy Services
In Section 4.2, ‘Facilities’ add the following subsection 4.2.6: Protection Systems for generating units in extended forced outage or in inactive reserve status are excluded from the requirements of this standard. However, the required maintenance and testing of the Protection Systems at these units must be completed prior to connecting the units to the Bulk Electric System (BES). Reason for the above comment: The above units are not connected to the BES and therefore do not affect the reliability of the BES. However, to ensure the reliability of the BES, required maintenance and testing of the Protection Systems at these units must be completed prior to connecting them to the BES.
Individual
Thad Ness
American Electric Power
Yes
No
On page 2 of the implementation plan, it is indicated that PRC-005-1, PRC-008-0, PRC-011-0 and PRC-017-0 shall be retired and that entities will be required to identify which components will be

addressed under PRC-005-1 or PRC-005-2. There is no wording to cover those components that are still being addressed under PRC-008-0, PRC-011-0 or PRC-017-0 during the implementation period.
No
This standard encompasses a very broad range of component types and functionality. It also encompasses broad segments of the BES. The proposed VSLs and VRFs place the same level of severity or priority on facilities that serve local load with that of an EHV facility. The percentages indicated in the VSLs seem to be too strict based upon the vast quantity of elements in scope and broad range of application.
No
Individual
Jose H Escamilla
CPS Energy
Yes
Yes
Yes
No
Table 1-5 The new standard requires that every 6 years it is verified that “each trip coil is able to operate the breaker,…”. The supplementary reference states that this requirement can be met by tracking real-time fault-clearing operations on the circuit breakers. With transmission breakers typically having dual trip coils, how can tracking real-time operations meet this requirement? Would a breaker operations where relays in both the primary and secondary trip coils indicated operation be sufficient or would some type of trip coil monitoring that showed coil energization be needed? Additionally, regarding the verification of all trip paths of the trip circuit. If a microprocessor relay is used to trip a breaker, and two contacts are paralleled on the relay through a single test switch for breaker tripping, would it be necessary to verify each contact independently or could an assertion of both contacts through the test switch be adequate? In this instance, the functionality of each contact would be fully identical. Table 1-2 A 3-month inspection is required for communications equipment that does not have “continuous monitoring or periodic automated testing for the presence of the channel function, and alarming for loss of function” has to be verified that the communication equipment is “functional” with a 3-month site visit. Would a carrier on-off system, that did not perform periodic check back testing, but did have an alarm contact (loss of power, failure, etc.) that was monitored through SCADA would need to have a 3-month inspection? According to the supplemental reference, this inspection should be to verify that the equipment is “operable through a cursory inspection and site visit”. It sounds as if this cursory inspection and site visit would accomplish the same as the alarm contact. It does not appear that end-end functional testing of the blocking signal is required by what is provided in the supplemental reference. Is this correct? Table 1-3 The maintenance activity for the 12 calendar year testing should include a little more specificity. It should have something stating the values provided to the relay are accurate. I know that this discussed in the supplemental reference, but requirement in Table1-3 sounds as if any relay that measured for loss of signal, such as a loss-of-potential function, would be sufficient when the purpose to verify that the signal not only gets to the relay but also has some accuracy as needed by the application of the relay.
Group
Tennessee Valley Authority
Dave Davidson
Yes
However, The requirement to perform battery cell internal ohmic measurements every 18 months for vented lead-acid batteries is excessive, and no technical justification is provided for an 18-month

interval. A 3-year internal ohmic test frequency is adequate to prove battery integrity. IEEE 450 does not provide a recommended interval for internal ohmic measurements. For standard capacity testing, the recommended interval is no greater than 25% of expected battery life. Our normal battery life is 20+ years, so the recommended capacity test interval would be about 5 years. EPRI also recommends capacity testing at 5 year intervals. There is no justification for performing internal ohmic measurements every 18 months (which equals every 7.5% interval of the expected battery life). Recommendation: Set the interval for battery internal cell ohmic testing at 3 years.
Yes
No
TVA has 590 Pilot Relay (Carrier Blocking) Terminals that are tested twice a year. After an extensive study of carrier failures over a 5-year period, it was determined that we were not having any failures that could have been prevented by a functional test. In January 2008, we reduced our frequency from 4 times per year to 2 times per year. The failure rate has remained about the same since that change. As PRC 005-2 currently states, the PM frequency would be 3 months. Allowing for a one-month grace period would actually require the interval to be set at 2 months. Therefore, the interval we used prior to 2008 (4 times per year) still would not make TVA compliant with the stated 3 month interval. TVA Power Control Systems is in the process of developing extensive PM tests for carrier terminals to complement the existing PM program. This PM would record signal levels, reflected power, line losses, and other pertinent data. It is my position that this PM will improve reliability more than increasing the frequency of the functional test.
No
Individual
Melissa Kurtz
US Army Corps of Engineers
Yes
Yes
Yes
Yes
The reference material provides a significant insight into the intent of the proposed changes to the standard. In some cases an interpretation is provided which is not supported by the explicit interpretation of the standard text. The SDT is encouraged to either attach the reference material to the standard or add relevant sections to standard as Background. The Background section could reference the Supplemental Reference & FAQ. The reference material provides more detail indicating that “Voltage & Current Sensing Device circuit input connections to the protection system relays can be verified by (but not limited to) comparison of measured values on live circuits or by using test currents and voltages on equipment out of service for maintenance. . . . . . The values should be verified to be as expected, (phase value and phase relationships are both equally important to verify).” This interpretation is not consistent with the text of the standard and would suggest that it be incorporated into Table 1-3.
Section 4.2.5.4 - please clarify generator connected station service transformer. We believe this to mean a station service transformer with no breaker between the transformer and teh generator bus. R3 - the term 'initiate resolution' is vague and needs to be further defined. Does this mean putting in a work order or is further action required. Data Retention: The proposed standard clarifies that two of the most recent records of maintenance are to be retained to demonstrate compliance with the prescribed maintenance intervals. When equipment is replaced, the reference information indicates that the information associated with the original equipment must be retained to show compliance with the standard until the performance with the new equipment can be established. This is not explicitly stated in the requirements and warrants a comment.

Group
Imperial Irrigation District
Jose Landeros
Yes
Yes
Yes
No
Group
PNGC Comment Group
Ron Sporseen
No
We agree the changes to the tables have added clarity, but disagree with the maintenance intervals for DC supply. Comments: “PNGC’s comment group views the Maximum Maintenance Interval for station DC Power Supply (Table -14a/b/c/d) to be unnecessarily onerous and restrictive to many smaller-rural entities, in the west and probably throughout the US, and this prevents us from being able to support PRC-005-2 as written. We make these comments with the understanding that others have made similar comments in the past but we feel strongly that this is an important issue worthy of further review by the SDT. We believe a quarterly inspection schedule can be met while at the same time allowing entities the flexibility they need. IEEE 1188-2005 suggests a quarterly inspection schedule for lead acid batteries and we believe the standard interval for verifying and inspecting dc supply should be 3 months with a maximum interval of 6 months. This meets the quarterly threshold and gives some flexibility to account for unusual conditions. There are substations in Pacific Northwest rural areas that can be inaccessible during long periods of time during the winter, potentially exposing an entity to sanction if weather conditions prevent access to equipment for an extended period of time. Additionally, due to a smaller workforces and greater distances between equipment subject to PRC-005, small-rural entities face obstacles that large entities may not have. The three month maximum interval assumes ideal conditions and resource access and is not realistic. We thank the SDT for considering our comments.”
Yes
Yes
Yes
Section 9.2 (copied below)indicates that small entities can utilize Performance-Based PSMP if they aggregate with other entities. Does this section indicate that only a parent entity with individually owned components can aggregate, or can independent entities under a G&T aggregate? In other words, individual DP/LSE/TOs with different audits. Can they aggregate under a common PSMP for performance based maintenance? 9.2 Frequently Asked Questions: I’m a small entity and cannot aggregate a population of Protection System components to establish a segment required for a Performance-Based Protection System Maintenance Program. How can I utilize that opportunity? Multiple asset owning entities may aggregate their individually owned populations of individual Protection System components to create a segment that crosses ownership boundaries. All entities participating in a joint program should have a single documented joint management process, with consistent Protection System Maintenance Programs (practices, maintenance intervals and criteria), for which the multiple owners are individually responsible with respect to the requirements of the Standard. The requirements established for performance-based maintenance must be met for the overall aggregated program on an ongoing basis. The aggregated population should reflect all factors that affect consistent performance across the population, including any relevant environmental factors such as geography, power-plant vs. substation, and weather conditions.

Group
Arizona Public Service Company
Janet Smith, Regulatory Affairs Supervisor
No
Although considerable clarity was achieved in the structuring of the table for the different types of technologies associated with the DC supply, there is issue on the maximum allowable intervals. The standard remains too prescriptive in the intervals and maintenance activities. As an example it is believed the intent of the interval for verifying voltages and inspecting electrolyte levels and unintentional grounds level would be every 3 months. However, for the entity to ensure compliance and not incur a violation it would have to have a shorter interval, probably every 2 months just to ensure compliance and not incur a violation. The 3 month interval is in question based on programs that have been in service for many years where four months have been proven as reliable for operation, an even shorter period than 3 or 4 months is not only a burden but an unnecessary expense without a benefit of increase reliability of the Bulk Electric System.
Yes
NERC continues to be too prescriptive in the standard. For example, Table 1-4(a) requires battery verifications and inspection every three months. We have been performing similar tests every four months for over a decade, with no adverse consequences. Although FERC Order 693 directs NERC to establish maximum allowable intervals, the maximum interval must be "appropriate to the type of protection system and its impact on the reliability of the Bulk-Power System." (Order 693 at 1475) The Standard Drafting Team (SDT) has not demonstrated a mechanism that connects the maximum maintenance interval with its impact on the reliability of the Bulk-Power System. An example can be found on the bottom of page 18 and the top of page 19 of the Consideration of Comments on Protection System Maintenance [Project 2007-17] for draft 3. Although the commenting organization provided a concrete example of successful maintenance under a longer interval, the Standards Drafting Team commented that it "… believes that 18-months is the proper interval for this activity." (Emphasis added) An organization cannot challenge the SDT's beliefs, only facts. The basis for each maximum maintenance interval, with appropriate linkage to its impact on the reliability of the Bulk-Power System, needs to be published and voted upon so that factual based proposals to modify the maximum interval can be rationally challenged.
Individual
Kenneth A. Goldsmith
Alliant Energy
Yes
Yes
No
The LOW and HIGH VSL for R2 are the same. There are additional possibilities for the LOW, but it is possible to be in both the LOW and HIGH VSL at the same time. We recommend removing #1 in the LOW VSL category to resolve the issue.
Yes
Comment 1 If PRC-005-2 is going to incorporate PRC-008 (UFLS) and PRC-011 (UVLS) the Purpose needs to be revised to include Distribution Protection Systems designed to protect the BES. Comment 2 We do not believe a distribution relaying system, designed to protect the distribution assets, that may open a transmission element (ie; breaker failure) should be considered part of the BES Protection System. R1 should add the following sentence "Distribution Protection Systems intended solely for the protection of distribution assets are not included as a BES Protection System, even if they may open a BES Element." Comment 3 Table 1-5 (Component Type – Control Circuitry) Item 4 –

“Unmonitored control circuitry associated with protective functions” require a 12 calendar year maximum maintenance interval. We believe UFLS and UVLS control circuitry should be exempted from this requirement. It would take multiple failures to have any impact, and the impact on the BES would be minimal.
Group
MRO's NERC Standards Review Subcommittee
Carol Gerou
Yes
Yes, however, in the “Supplemental reference and FAQ” document on page 65 this is one area of concern. Page 65, paragraph 4 “... the type of test equipment used to establish the baseline must be used for any future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer’s equipment.” While we understand the importance of creating a baseline, it’s not feasible to expect the test equipment to be the same as the manufacturer’s test equipment or even the same test equipment over the life of the battery. The expected life of a battery may be in excess of 15 years and it is not feasible to expect that the type of test equipment will not change during this period. We suggest changing the wording to read that consistent test equipment should be used to provide consistent/comparable results.
Yes
Yes
No
In the checkbox for Requirement R3 please change the wording to read, “Maintenance Correctable Issue - Failure of a component to operate within design parameters such that it cannot be restored to functional order by repair or calibration during performance of the initiating on-site activity. Therefore this issue requires follow-up corrective action.”
Individual
Kirit Shah
Ameren
Yes
Please carry the grid across in Table 1-4(f) to show the Maintenance Activities that go with the Component Attribute.
Yes
While we agree with the Implementation Periods, it would be best to alter R2 and R3 implementation such that components with maximum allowable intervals of 1 year or longer align with a true calendar year (i.e. begin with January 1).
Yes
Yes
1. Comments: Supplement FAQ 12.1 on page 51 final sentence states that documentation for replaced equipment must be retained to prove the interval of its maintenance. We oppose this because: the replaced equipment is gone and has no impact on BES reliability; and such retention clutters the data base and could cause confusion. For example, it could result in saving lead acid battery load test data beyond the life of its replacement. Since BES Element protection is the objective, we suggest a compromise of keeping the evidences of last test for the removed equipment and using that with the equivalent function replacement equipment commissioning or in-service date to prove interval. 2. Clarify p17 Table 1-4(e) interval meaning. We think this means we need to verify the Station dc supply voltage on 12 calendar year interval if unmonitored, or no periodic maintenance if monitored as stated. 3. In Supplement examples on pp 22-23, replace “Instrumentation transformers” with “Verify that current and voltage signal values are provided to the protective relays” to be consistent with Table 1-3. 4. Remove “Reverse power relays” from the sample list of

generator devices in Supplement p31 because reverse power relays are applied for mechanical protection of the prime mover, not electrical protection of the generator. 5. Revise Supplement Figure 1 & 2 Legend p83 to align with Draft 4 (a) state “Protective relays designed to provide protection for BES Element(s)”. (b) state “Current and voltage signals provided to the protective relays” 6. Please add a Performance-Based maintenance example for control circuitry, and /or voltage and current sensing.
Measure M3 on page 5 should apply to 99% of the components. “Each … shall have evidence that it has implemented the Protection System Maintenance Program for 99% of its components and initiated….” PRC-005-2 unrealistically mandates perfection without providing technical justification. A basic premise of engineering is to allow for reasonable tolerances, even Six Sigma allows for defects. Requiring perfection may well harm reliability in that valuable resources will be distracted from other duties. 2. Define BES perimeter in accordance with Project 2009-17 Interpretation. Facilities Section 4.2.1 “or designed to provide protection for the BES” needs to be clarified so that it incorporates the latest Project 2009-17 interpretation. The industry has deliberated and reached a conclusion that provides a meaningful and appropriate border for the transmission Protection System; this needs to be acknowledged in PRC-005-2 and carried forward. The BOT adopted this 2/17/2011. 3. Battery inspection every 4 months is sufficient. IEEE battery maintenance standards call for quarterly inspections. These are targets, though, not maximums. An entity wishing to avoid non-compliance for an interval that might extend past three calendar months due to storms and outages must set a target interval of two months thereby increasing the number of inspections each year by half again. This is unnecessarily frequent. We suggest changing the maximum interval for battery inspections to 4 calendar months. For consistency, we also suggest that all intervals expressed as 3 calendar months be changed to 4 calendar months.
Individual
Rex Roehl
Indeck Energy Services
No
The tables are limited to a few battery technologies and will be out of date in short order with the many types of advanced batteries already on the market. The testing requirements should be performance based as opposed to prescriptive.
No
The last part of the implementation plan is vague, if not undefined. The implementation should “follow the previous maintenance intervals until all maintenance is transitioned to the new intervals.”
No
The VSL’s for R1 should combine the ones for Lower, Moderate and High VSL into Lower VSL. The Severe VSL should be moved to the Moderate VSL. Because R1 is administrative, it shouldn’t have High or Severe VSL’s. The R2 High VSL (3 yrs) is more stringent than the Severe VSL (5 yrs). The R3 VSL’s need to have combined numbers of components or percentages because small generators may only have 25 relays or 1 battery and would be categorized as High or Severe VSL with a few components affected. The percentage could apply to RE’s with more than 250 components included in the PSMP. The Medium VRF for R1 should be Low VRF because R1 is administrative. Only the performance of the maintenance has anything more than Low VRF. The Medium VRF for R2 is OK. Having a High VRF for R3 is without basis. R3 should have Medium VRF.
No
Individual
Kevin Luke
Georgia Transmission Corporation
No
We need clarification on the UFLS or UVLS system Station DC Supply test. We trip the high side device (non-BES asset) for each of our distribution stations UFLS or UVLS schemes, not the individual distribution breakers. It is hard to distinguish what maintenance interval and maintenance activities we should engage for Station DC Supply test. Since the device is not a distribution breaker as

mentioned in the Table 1-4 (a-f) we would be conservative and choose to perform maintenance at all our distribution stations with UFLS or UVLS schemes as per Table 1-4(a). Reading the statements in the Supplementary Reference and FAQ, we notice our devices perform similar functions as the distribution breakers. Reference pg 60 of Supp. Ref. and FAQ paragraph 4. Since tripping the high side device of a distribution transformer still constitutes a distributed system would our system meat the exclusion criteria although it is not a distribution breaker, would this meet the same requirements and exempt the station from Table 1-4(a) and require only maintenance for DC systems as per Table 1-4(e)? Please clarify. We recommend changing the term distribution breaker to distribution asset interruption device or non-BES equipment interruption device.
Yes
Yes
Yes
See comments for item 1 and continue clarification where we could include high side or distributed interrupting devices, exchange nomenclature removing distribution breaker and adding distributed interrupting device or non-BES equipment.
Individual
Andrew Z Pusztai
American Transmission Company, LLC
Yes
Yes, however, in the “Supplemental reference and FAQ” document on page 65 there are two areas of concern. - Page 65, paragraph 4 “... the type of test equipment used to establish the baseline must be used for any future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measured used by different manufacturer’s equipment.” While ATC understands the importance of creating a baseline, it is not feasible to expect the test equipment be the same as the manufacturer’s test equipment or even the same test equipment over the life of the battery. The expected life of a battery may be in excess of 20 years and it is not feasible to expect that the type of equipment will not change during this period. - Page 65, paragraph 6 “... all manufacturers of internal ohmic measurement devices have established libraries of baseline values ...” ATC question’s the availability of baseline libraries for all manufacturers considering the variety and longevity of installations.
Yes
Change the text of “Standard PRC-005-2 – Protection System Maintenance” Table 1-5 on page 19, Row 1, Column 3 to: “Verify that a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device.” Or alternately, “Electrically operate each interrupting device every 6 years” Trip coils are designed to be energized no longer than the breaker opening time (3-5 cycles). They are robust devices that will successfully operate the breaker for 5,000-10,000 electrical operations. The most likely source of trip coil failure is the breaker operating mechanism binding, thereby preventing the breaker auxiliary stack from opening and keeping the trip coil energized for too long of a time period. Therefore, trip coil failure is a function of the breaker mechanism failure. Exercising the breakers and circuit switchers is an excellent practice. We would encourage language that would suggest this task be done every 2 years, not to exceed 3 years. Exercising the interrupting devices would help eliminate mechanism binding, reducing the chance that the trip coils are energized too long. The language as currently written in table1-5 row 1, will also have the unintentional effect of changing an entities existing interrupting device maintenance interval (essentially driving interrupting device testing to a less than 6 year cycle). Change the text of “Standard PRC-005-2 – Protection System Maintenance” Table 1-5 on page 19, Row 3, Column 2 to: “12 calendar years” The maximum maintenance interval for “Electromechanical lockout and/or tripping devices which are directly in a trip path from the protective relay to the interrupting device trip coil” should be consistent with the “Unmonitored control circuit” interval which is 12 calendar years. In order to test the lockout relays, it

may be necessary to take a bus outage (due to lack of redundancy and associated stability issues with delayed clearing). Increasing the frequency of bus outages (with associated lines or transformers) will also increase the amount of time that the BES is in a less intact system configuration. Increasing the time the BES is in a less intact system configuration also increases the probability of a low frequency, high impact event occurring. Therefore, the Maximum Maintenance Interval should be 12 years for lockout relays. ATC recognizes the substantial efforts and improvements to PRC-005-2 that have been made and appreciate the dedicated work of the SDT. We appreciate the removal of Requirement R1.5 and R4 and other clarifications from draft 3. ATC's remaining concern for PRC-005-2 is with definition and timelines established in Table 1-5. ATC believes that, as written, the testing of "each" trip coil and the proposed maintenance interval for lockout testing will result in the increased amount of time that the BES is in a less intact system configuration. ATC hopes that the SDT will consider these changes.
Group
The Detroit Edison Company
Daniel Herring
Yes
Yes, the tables do provide more clarity. It is much easier to understand the requirements now that they are broken down by technology, and the exclusion of intervals on certain activities based on the individual monitoring attributes is helpful. I appreciate the thought that went into revising this.
Yes
No
R2 - It appears that the Lower VSL point 1) and High VSL are identical.
No
Countable Event - This definition should be clarified. As it stands, it appears that if a technician were to adjust the settings on an electromechanical relay - even if it were not outside of the entity's acceptable tolerance - it would need to be classified as a countable event. I would recommend that the definition be limited to repairing or replacing a failed component during the maintenance activity. These activities would address conditions that would potentially cause a Protection System misoperation (either a failure to trip or an unintentional trip). Routine maintenance activities to bring component test values back within tolerance should be excluded from the definition of a Countable Event. These activities are performed to keep the protection systems performance at its most ideal state. In addition, the definition as stated appears to classify battery maintenance activities such as cleaning corrosion, adding water, or applying an equalize charge, as countable events. If this is the intent, I disagree. These are activities that are expected to occur on a regular, routine basis due to the chemical properties of the battery (as described at length in the Supplementary Reference). As such, they should also not be classified as countable events. Table 1-1 and Table 1-5 Based on experience with DECo equipment, a 6 year interval for testing monitored relays and performing tests on the breaker trip coil is substantially shorter than required. Currently, the interval for both is 10 years. This interval lines up both with the Transmission Owner's interval for relay maintenance as well as the maintenance interval for the associated current interrupting devices. I would recommend that these intervals be extended, at minimum, back to the 7 year interval proposed in Draft 2 - if not longer. Table 1-4 (a, b, c, e) - Station dc supply using any type of battery I recommend that the maintenance activity to "Verify: Station dc supply voltage" be clarified to state that the voltage should be measured at the positive and negative battery terminals. Until you get to page 72 of the Supplementary Reference, you do not know if this means to check the battery voltage or the bus voltage. The "Station dc supply" could refer to the entire dc system. It needs to be made clear in the table that you are referring to the battery. Also, I noticed that there is no longer a requirement to measure individual cell voltages. I was wondering if you could explain the rationale behind that. Checking for voltages that are out of specification in individual cells helps to identify weak cells that may need to be replaced, if corrective action taken on them does not improve their condition. Individual cell voltage readings, along with ohmic readings, have been an industry standard that I believe many, if not most, companies adhere to. Table 1-4 (a, b, c, d) I recommend eliminating the 3 month requirement. We have found annual inspections to be sufficient in catching problems early enough to take corrective action. Page 30 of the Supplementary Reference states that the SDT

believes that routine monthly inspections are the norm. While this may be the case at manned stations, it is not at unmanned stations. The amount of paperwork that would be required to demonstrate compliance is overwhelming and would be an immense burden. I have seen your suggestion in past draft comments of the same nature that if we don't want to do the 3 month inspections, then we should utilize more advanced monitoring. This is not something that can be implemented in a short time frame. It would take years to put all of that technology in place, and is rather cost prohibitive. Furthermore, some of the monitoring technologies that would enable you to forgo the 3 month requirement do not exist yet (to my knowledge). I recommend keeping with the 18 month requirement. If that seems too long, based on past experience I think a 12 month requirement would suffice. Table 1-4 (c) I propose keeping the option to evaluate ohmic values to baseline. Table 1-4 (a, b) For the requirement to evaluate the ohmic values to baseline, is a checkbox stating that you did this sufficient, or would a report/graph/etc listing the actual baseline and current value be required? Table 1-4 (f) The first attribute is regarding high and low voltage monitoring and alarming of the battery charger voltage to detect charger overvoltage and charger failure. Would a low voltage alarm combined with high voltage shutdown (but not a high voltage alarm) meet this requirement? The high voltage shutdown will shut the charger down in a high voltage condition, and therefore result in a low voltage alarm, so the outcome is the same.
Individual
John Bee
Exelon
Yes
What kind of component we are talking about in table 1.4(d) “Station DC Supply using Non Battery Based Energy Storage” for switchyard in nuclear plants?
In response to Exelon’s comments provided to drafts 1, 2, and 3 of PRC-005, the SDT did not explain why a conflict with an existing regulatory requirement is acceptable. The SDT previously responded that a conflict does not exist and that the removal of grace periods simply is there to comply with FERC Order directive 693. In response to draft 3 of PRC-005, the SDT stated that "If several different regulatory agencies have differing requirements for similar equipment, it seems that the entity must be compliant with the most stringent of the varying requirements. In the cited case, an entity may need to perform maintenance more frequently than specified within the requirements to assure that they are compliant." Again this does not explain why a conflict with an existing regulatory requirement is acceptable. This response does not answer or address dual regulation by the NRC and by the FERC. Specifically, the request has not been adequately considered for an allowance for NRC-licensed generating units to default to existing Operating License Technical Specification Surveillance Requirements if there is a maintenance interval that would force shutting down a unit prematurely or become non-compliant with PRC-005. Therefore, Exelon again requests that the SDT communicate with the NRC and with the FERC to ensure a conflict of dual regulation is not imposed on a nuclear generating unit without the necessary evaluation. In addition, the SDT still did not fully evaluate or address the concern related to the uniqueness of nuclear generating unit refueling outage schedules. Although Exelon Nuclear agrees with the SDT that the maximum allowed battery capacity testing intervals of not to exceed 6 calendar years for vented lead acid or NiCad batteries (not to exceed 3 calendar years for VRLA batteries) could be integrated within the plant’s routine 18 month to 2 year interval refueling outage schedule, the SDT has not considered that nuclear refueling outages may be extended past the 18 month to 2 year "normal" periodicity. There are some unique factors related to nuclear generating units that the SDT has not taken into consideration in that these units are typically online continuously between refueling outages without shutting down for any other required maintenance. Historically, generating units have at times extended planned refueling outage shutdown dates days and even weeks due to requests from transmission operations, fuel issues and electrical demand. Without the grace period exclusion currently allowed by existing maintenance programs, a nuclear plant will be forced to either extend outage duration to include testing on an every other refueling outage (i.e., every four years to ensure compliance for a typical boiling water reactor) or leave the testing on a six year periodicity with the vulnerability of a forced shut down simply to perform maintenance to meet the six year periodicity or a self report of non-compliance. To

ensure compliance, the nuclear industry will be forced to schedule battery testing on a four year periodicity to ensure the six year periodicity is met, thus imposing a requirement on nuclear generating units that would not apply to other types of generating units. The SDT response to this question in draft 3 is that "(t)he 18-month (and shorter) interval activities are activities that can be completed without outages – primarily inspection-related activities. An entity may need to perform maintenance more frequently than specified within the requirements to assure that they are compliant." Respectfully Exelon requests that the SDT review and evaluate the concern.
Individual
Glen Sutton
AtCO Electric ltd
Table 1-4: ATCO Electric has a number of remote substations that are difficult to access. The requirement for a 3 calendar month inspection for electrolyte level is too frequent. The requirement would become achievable if electrolyte level inspections were moved to the 18 calendar months category, or if the 3 calendar months frequency were increased to 8 calendar months. Table 1-4(b): for the same reasons, the requirement of a 6 calendar month inspection of individual battery cell/unit internal ohmic values is too frequent. The requirement would become achievable if battery cell/unit internal ohmic value inspections were moved to the 18 calendar months category, or if the 6 calendar months frequency were increased to 14 calendar months. Table 1-4(c): the requirement of a 6 calendar year performance service or modified performance capacity test should be removed. From our experience, there is no benefit in doing battery load tests. Instead, we apply verification of battery intercell resistance as a more efficient method of monitoring battery condition, which provides an 8 to 14 month lead time to replace a battery unit/cell before it goes dead.
Table 1-2: the requirement for a 12 calendar year verification for the channel and essential signals' performance should be removed. We do not see benefit in the maintenance activities under level 2 (the 12 calendar year requirement) and suggest merging it with level 3 (the "no periodic maintenance specified" requirement). The 'loss of function' alarm, will be considered as a countable event to fall under requirement R3 and dealt as maintenance correctable issue. Table 1-5: the requirement of 6 calendar year verification for electrical operation of electromechanical lockout and/or tripping auxiliary devices should be revisited, considering that: • It is not feasible to exercise a lockout relay during maintenance due to high risk to the in-service facility, as well as the complexity of lockout relay connections and protection schemes. Instead, we propose a DC ring test, which verifies the continuity of control circuitry and eliminates the risk impact of lockout or auxiliary tripping device operations. • The interval is too frequent. The requirement would become achievable if the 6 calendar year frequency were increased to 12 calendar years, to be in line with microprocessor relay maintenance frequency
Individual
Claudiu Cadar
GDS Associates
Yes
Yes
No
• Suggest clarification of the VSL for R2. It appears that R2 Lower VSL is also contained in the R2 High VSL. • If the maintenance is completed prior to the maximum interval, would it then reset the clock? Or should it read that maintenance should be done at least once per quarter, etc. • The plan should split into generation time horizons and transmission time horizons since these can be significantly different
Yes
The standard should include a footnote indicating this document as reference
A. Requirement R1 • Suggest changing the language in R1.2 to read "Identify which maintenance

method such as the time-based, performance-based (detailed in PRC-005 Attachment A), or a combination of the two would be appropriate to be used for each type of Protection System component. Based upon their own constructive type, all batteries associated with the station DC supply shall be included in a time-based maintenance program consistent with Table 1-4(a) through Table 1-4(f)" • Suggest changing the language for the first paragraph in R1.3 to read "Establish the occurrences associated with the time-based maintenance programs up to but no less than the time intervals specified in Table 1-1 through Table 1-5, and Table 2. Consequently, include all applicable monitoring attributes and related maintenance activities characteristic to each type of Protection System component specified in Table 1-1 through Table 1-5, and Table 2" • Suggest adding a sub-requirement such as R1.5 to read "Include documentation of maintenance, testing interval and their basis and a summary of testing procedures" B. Requirement R3 • The redline version of the standard is misleading. Requirement R3 is crossed out and then replacing requirement R7 which is also crossed out. • The wording "[…] initiates resolution of any identified maintenance correctable issues" it is vague. What a responsible entity should do to become compliant with this requirement? We also believe that is not sufficient to just "initiate resolution"; the standard should call for corrective actions to be performed within the maintenance time interval. • The "identified maintenance correctable issues" may not be a proper choice. The name of the new term suggests that is about issues that can be corrected during maintenance, while the definition from the clean version explains otherwise?! C. Additional requirement • Suggest adding a requirement to read "The Transmission Owner, Generator Owner, and Distribution Provider shall provide documentation of its PSMP and implementation to the appropriate Regional Reliability Organizations on request (within 45 calendar days)." • Add measure for the evidence on documenting the PSMP from the additional requirement D. General comments and notes • If you own electro-mechanical relays and microprocessor based relays is there a need to keep two different logs for these? • On table 1-4 the generator CTs should be tested earlier than the suggested 12 years due to exposure of continuous mechanical stress • Clarify table 1-5 to address verification tests on different circuits. Suggest that the Table 1-5 to read "Complete a terminal test of unmonitored circuitry" instead of the "Unmonitored control circuitry associated with protective functions" • In what instances (what extent) would the standard allow using the real time breaker operation to be considered maintenance as applicable to different types of relays involved in the real time event? This is briefly emphasized under TBM at paragraph 5.1 from the supplementary reference document?
Group
ISO/RTO Standards Review Committee
Albert DiCaprio
The SRC disagrees with the change to the term under 4.2.1. "Protection Systems designed to provide protection for BES elements." We support keeping the previous version's wording of 4.2.1. "Protection Systems applied on, or designed to provide protection for the BES." The revised wording expands the fundamental purpose of the NERC PRC-005 standard from being focused on ensuring relays intended to protect the reliability of the BES are maintained to a standard whose intent is to ensure all BES facilities have relay maintenance programs. Although we do not disagree with maintaining all relays, regardless of what their intended purposes are, it should not be the purpose of a NERC standard to police all protection schemes beyond those needed for interconnected reliability. There are numerous protective relays employed on facilities interconnected to the BES but their purpose may be for operating preference or service/equipment quality purposes such as reclosing schemes and transformer sudden pressure relays. We believe the NERC PRC-005 standard should be focused on maintenance of those protective relays which are needed to ensure that the loss of a single element does not cause cascading effects on the bulk power system.
Group
Transmission Access Policy Study Group
Cynthia S. Bogorad

The scope of the equipment to which the draft standard applies is over-broad. Specifically, PRC-005-2 should not apply to non-relay equipment for UFLS and UVLS systems. Subjecting UFLS and UVLS batteries, instrument transformers, DC control circuitry, and communications to the requirements of PRC-005-2 would drastically increase the scope of equipment covered by the standard, with no corresponding benefit to reliability, for the following reasons. In contrast to transmission and generation protection systems and SPSs, for which there are typically two protection systems per facility and therefore per fault, UFLS and UVLS deal with widespread events. For any under-voltage or under-frequency event, there are literally hundreds of UFLS/UVLS relays to respond. It is therefore far less critical if one UFLS or UVLS relay fails to operate properly. Furthermore, transmission is typically not radial (in fact, radials to load are excluded from the BES). But distribution circuits, where UFLS and UVLS systems are located, are usually radial. Testing some of the non-relay equipment to which the draft standard applies would require blacking out the customers served by that radial. In other words, the draft standard would require entities to definitely cause blackouts in an attempt to prevent very unlikely potential blackouts. This is plainly not justified from a harm/benefit perspective. Finally, many of the types of non-relay equipment to which the standard would apply are in effect tested by faults. Specifically, faults happen on distribution circuits (where UFLS and UVLS systems are located) more frequently than on transmission circuits, due to such things as animal contacts and car accidents. Any such fault is in fact a test of the all the equipment that is involved in clearing the fault. There is no need to require separate tests of that equipment, any more than we would require tests of a phone line that is used on an everyday basis; you already know that the phone works.
Individual
Gerry Schmitt
BGE
Yes
No comments.
Yes
No comments.
Yes
No comments.
Yes
The supplementary reference on page 30, under the question beginning “Our maintenance plan requires…” states that an entity is “out of compliance” if maintenance occurs at a time longer than that specified in the entity’s plan, even if that maintenance occurred at less than the maximum interval in PRC-005-2. But then on page 35, under the question, “How do I achieve a grace period without being out of compliance” provides an example of scheduling maintenance at four year intervals in order to manage scheduling complexities and assure completion in less in less than the maximum time of six calendar years. This is conflicting advice. The FAQ /supplementary reference should be revised so that it does imply that an entity is out-of-compliance by performing maintenance more frequently than required. Avoiding compliance risk is one reason to do this, but there are other valid motives not directly related to reliable protection system performance. Testing of PT’s and CT’s (12 year max) is non invasive and convenient to schedule at the same time as relays (6 year max) just to keep procedures consistent and reduce program administration. Testing of ties to other TOs or GOs may have to be scheduled more frequently than preferred in order to synchronize schedules.
No comments.
Group
FirstEnergy
Sam Ciccone
Yes
No
Although we agree with the timeframes being afforded to achieve compliance, we suggest the

following changes: 1. During the last comment period, we suggested changes to the wording regarding retirement of existing standards on page 2. We do no see a response to these comments. Therefore, we would like to reiterate that the four existing standards are to be retired upon the effective date of the new standard and not upon regulatory approval. 2. In 4a of the plan, since the timeframe for 30% completion is 3 calendar years, we suggest a change to three calendar years for the parenthetical phrase “(or, for generating plants with scheduled outage intervals exceeding two calendar years, at the conclusion of the first succeeding maintenance outage)”. Change “two” to “three”. 3. We suggest the implementation plan be included within the body of the standard. It is very burdensome for entities to have to look for the implementation plan and we believe that a “one-stop shopping” approach would alleviate this burden.
Yes
Yes
We do not agree with the following wording on page 37 of the reference document: (1) “If your PSMP (plan) requires more activities then you must perform and document to this higher standard.” and (2) “If your PSMP (plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard.” We continue to believe that the auditor is required to audit to the standard. If the standard requires maintenance intervals every 6 years, this is what the auditor should verify. This was also verified in the recent NERC Workshop at which it was confirmed that “auditors must audit to the standard”. To this end, we also suggest changes to Requirement R3 as explained in our comments in Question 5.
FE offers the following additional comments and suggestions: We do not agree with the wording of requirement R3. The entity is only required to meet the minimum maintenance intervals of the standard as outlined in Tables 1 and 2. We offer a scenario where an entity states that they will go above the standard and maintain relays on a 4 year cycle. The standard, in meeting an adequate level of reliability, sates that this activity must be performed every 6 years. If the entity happened to miss the 4 year timeframe, deciding from a business standpoint to delay the maintenance to the 5th year, an auditor can find the entity non-compliant per the guidance and wording of the requirements in this standard. However, the entity still exceeded an adequate level of reliability by performing the maintenance within 5 years. This scenario would be very unfortunate to the entity that has essentially done their part in providing reliability to the bulk power system, yet they would be punished for not meeting their more stringent timeframes. This standard’s guidance and requirements sends an adverse message to industry. It essentially punishes an entity for going above and beyond the standard except on a few rare occasions. If this were to happen, that entity, and possibly others, would not see the value in going above a standard. It would make entities meet the bare minimum requirements, essentially reducing overall system reliability. Therefore, we suggest the following wording for requirement R3: “R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement its PSMP to ensure adherence to the minimum requirements as outlined in Tables 1 and 2, and initiate resolution of any identified maintenance correctable issues.”
Individual
Michael Moltane
ITC
Yes
The re-structured tables are easier to use.
Yes
Yes
No
We agree with the combination of the two. One document with the FAQ’s grouped with the supplemental topics makes it easier to review the whole topic.
For Battery System: - Table 1-4(a) o The maximum maintenance interval for the majority of the battery maintenance is listed at “18 calendar months”. The current ITC Standard is “once per calendar year and a calendar year is defined as a twelve-month period beginning January 1st and ending December 31st “. ITC would like the maximum maintenance interval at “once per calendar year” -

Table 1-4(b) o VRLA (Valve Regulated Lead Acid) batteries have an additional inspection at 6 calendar months that includes inspecting the condition of all individual units by measuring the battery cell/unit internal ohmic values. This is in addition to the “18 calendar months” inspection. ITC would like to be consistent with the VLA (Vented Lead Acid) batteries and have only one internal ohmic value inspection once per calendar year. For Battery System: - Table 1-4(a) o The maximum maintenance interval for the majority of the battery maintenance is listed at “18 calendar months”. The current ITC Standard is “once per calendar year and a calendar year is defined as a twelve-month period beginning January 1st and ending December 31st “. ITC would like the maximum maintenance interval at “once per calendar year” - Table 1-4(b) o VRLA (Valve Regulated Lead Acid) batteries have an additional inspection at 6 calendar months that includes inspecting the condition of all individual units by measuring the battery cell/unit internal ohmic values. This is in addition to the “18 calendar months” inspection. ITC would like to be consistent with the VLA (Vented Lead Acid) batteries and have only one internal ohmic value inspection once per calendar year. Auxiliary Relays: • ITC does not agree with the 6 year interval for Aux relays in the trip circuit. Although they are EM relays they are simple and have very few moving parts. We believe the maintenance period for auxiliary relays should be 12 years and they should be in conjunction with the control circuit. We recognize that Draft 4 only includes auxiliary relays that are directly in the trip path. That is an improvement in Draft 4. In general, auxiliary relays are very reliable; only certain relay types have been proven to be problematic. A known relay type (HEA) has been proven to be problematic if not exercised frequently. The standard should not require a 6 year interval period for all other auxiliary relays. We believe problematic relays should be addressed through use of a NERC Alert process. Don’t cut down the tree for a bad apple.
Individual
Bill Middaugh
Tri-State G&T
On Table 1-2, page 11: The standard describes the following component attributes, “Any unmonitored communications system necessary for correct operation of protective functions, and not having all the monitoring attributes of a category below.” How does this apply to redundant communication systems? If the primary communications channel fails the protective relay automatically fails over to the back-up channel and continues to function properly. Are redundant communication channels excluded from this component attribute and associated interval? Please clarify the term correct operation and how it applies to redundant communication systems.
The draft standard requires the PSMP to include maintenance and testing intervals for Station DC supply associated with protective functions (including batteries, battery chargers, and non-battery-based dc supply). Does this requirement include DC systems (batteries not included in station batteries) used by communication systems necessary for the correct operation of protective functions?
On Page 19, Table 1-5, the standard requires that monitored electromechanical lockouts be maintained every 6 years. Why is there inconsistency in the interval between the monitored lockouts and monitored relays?
M1 - Why is the document necessary to be “current or updated?” Eliminate “or updated.” R1 VSL - Second item in Severe VSL is not addressed in any lower VSL. Should there also be a comparable violation in Lower and Moderate? R2 VSL – Keep the comment about the redundancy in Lower VSL and High VSL for clarifying the difference between the two.
Individual
Don Schmit
Nebraska Public Power District
No
Comments: The restructured tables are indeed an improvement; however the tables still need some work for clarity: Table 1-5: Unmonitored control circuitry has a maintenance activity of “Verify all paths of the control and trip circuits.” The wording of “control and trip circuits” leads to circuit verification of more than just trip circuits. In fact multiple circuits would have to verified, such as station house load transfer schemes. Providing documentation to an auditor to prove all paths have been tested will be difficult and is considered excessive. The paperwork required to prove compliance

is extremely excessive for this requirement and doesn’t provide a benefit to reliability. Table 1-5: Table 1-5 requires trip checking every six calendar years for trip coils and electromechanical lockout and/or tripping auxiliary devices. Every six years is excessive, when sutiable monitoring is used. We recommend verification of these components be completed at the same frequency as the associated relay testing when monitoring is used. For electromechanical, no more than every 6 calendar years, for microprocessor, no more than 12 calendar years. Table 2: The interrelationship between Tables 1-1 through 1-5 and Table 2 is ambiguous. Tables 1-1 through 1-5 “component attributes” columns references Table 2 in many cases as the criteria for maximum interval. However, each table entry has a maximum maintenance interval listed as well. There are a few instances where the “trump” interval is not clear. Table 1-5 is a good example. Table 2 states that monitored devices (1-1 through 1-5) not having monitored alarm paths shall be tested every 12 years. However, Table 1-5 states that DC circuits with monitored continuity shall have no periodic maintenance. We suspect that Table 2 attributes needs further clarification to eliminate the confusion, both Table 2 attributes at first glance appear to say the same thing. However, after study it appears to address “detection” monitoring versus continuous (control center type) monitoring. We believe further distinguishing clarifications are needed to make it evident and clear.
Group
Western Area Power Administration
Brandy A. Dunn
Yes
Yes
Yes
Yes
Can the SDT add a better definition or clarification of “Calendar Year” as it pertains to PRC-005-2 and provide examples or parameters of Compliance with the Standard requirements and tables? Calendar Year is explained in various details within Pages 35-Pages 37 of the Supplementary Reference and FAQ. This important attribute of a TBM or TBM/CBM combination program is not easily found in the Table of Contents or section sub-headings.
Please explain or clarify the term “mitigating devices” used in Table 1-5 Control Circuitry, Page 19. This term is not well defined in the industry and not easily understood as “interrupting device” or “circuit breaker.”
Group
Luminant
David Youngblood
Yes
No comments
Yes
No comments
Yes
No comments
Yes
The document was valuable in understanding PRC-005-2 by providing clarification using practical protective relay system examples. Below are two comments for further improvement. 1. It would be beneficial if the document could provide additional information for relaying in the high-voltage switchyard (transmission owned) - power plant (generation owned) interface. While Figures 1 and 2 are typical generation and transmission relay diagrams, it would be helpful if protective relays

typically used in the interface also be included. For example, a transmission bus differential would remove a generator from service by tripping the generator lockout. 2. Figures 1 and 2 refer to a “Figure 1 and 2 Legend” table which provides additional information on qualifications for relay components. Should a footnote be used to point toward Reference 1 (Protective System Maintenance: A Technical Reference) located in Section 16?
The red-lined version did not agree with the clean copy. In reading the "red lined" document it appears that R3 was intended to be "Each Transmission Owner, Generation Owner, and distribution Provider shall implement and follow its PSPM and initiate resolution of any identified maintenance correctable issues."
Group
NextEra Energy
Silvia Parada Mitchell
Yes
Yes
Yes
No
Thank you for your diligent efforts in writing the draft standard. The draft standard and associated documents are well written and we believe, after approval, will be instrumental to improving the reliability of the BES. We have the following specific comments: a. The maximum maintenance interval of unmonitored Vented Lead-Acid (VLA) batteries should be changed from 3 calendar months to 12 calendar months. Today’s lead-calcium and lead-selenium-low antimony batteries do not have rapid water loss as compared to the legacy lead-antimony batteries. FPL’s operating experience has shown that electrolyte in today’s VLA cells do not require watering within a 12-month interval. In fact, battery manufacturers now recommend watering intervals of 2 to 3 years for some new batteries. b. The maximum maintenance interval to verify that unmonitored communications systems are functional should be changed from 3 calendar months to 12 calendar months. FPL’s operating experience has shown that power line carrier (PLC) failures are primarily due to PLC protective devices (MOVs, gas tubes & spark gaps). Automated testing such as PLC check-back schemes cannot test for failed PLC protective devices. We believe a 12 calendar month functional test is sufficient because of FPL’s operating experience. FPL’s operating experience has shown that power line carrier (PLC) failures are primarily due to PLC protective devices (MOVs, gas tubes & spark gaps). c. We believe the data retention requirements for R2 and R3 should be documentation for the two most recent maintenance activities. d. Regarding Maintenance Correctable Issue (page2) where it states: “..such that it cannot be restored to functional order during performance of the initial on-site activity”. This terminology is vague: Particularly” initial on-site activity”. Not sure what “functional order” means? The suggestion is to change to “..such that the deficiency cannot be restored to meet applicable acceptance criteria during the performance of the scheduled maintenance activity”. e. Regarding Maintenance Correctable Issue (page 2) and “R4” on Page 5, the suggestion is an entirely new “Maintenance Correctable” definition especially: “Therefore this issue requires followup corrective action”. Regarding this new definition: Why is it here? Is its purpose to ask us to do something with these issues if we discover them? Do issues identified as “Maint. Correctable” need to be tracked and reported in some manner? The referenced term “Maint. Correctable” is only used in PRC-005-2 in “R4” (page 5). The suggestion is to provide clarification. Is this “maintenance cotrrectable terminology implying that NERC PRC005-2 is opening up a new requirement for tracking and reporting resolution of “Maint Correctable” issues? The suggestion is to change to: “This issue includes any activity requiring further follow-up corrective action to restore operability outside of the applicable maint activity”. f. Regarding Countable Event (Page 3), the suggestion is an entirely new “Countable Event” definition. Why is this new term and definition “countable event” included in PRC-005-2 ? Note: In the PRC005-2 text ”countable event” is actually only referred to in PRC-005-2 in Attachment A under “Performance Based Programs” (not referred to in time based programs section). The recommendation is that the PRC-005-2 version explicitly clarify the definition of “countable event” to

clearly indicate that this term is applicable ONLY to “Performance Based Programs”. g. Regarding Countable Event (page 3), where the text says “Any failure of a component which requires repair or replacement, any condition discovered during the verification activities in Tables 1-1/1-5 which requires corrective action…..”, in the definition for “countable event” what does “corrective action” mean? PRC005-2 is unclear. Does the term “countable event” have any ties to “Maint Correctable” issues. The suggestion is to Consider changing wording from “corrective action” to “which requires > 7 days to correct” and clarify whether or not ”countable event” has any correlation to “Maint Correctable”events as discussed on page 2 and in R4? If so please provide language clarifying this correlation.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
No
We commented on this before and we will comment again. The time periods for FERC-jurisdictional entities and non-jurisdictional entities should have at least a 3-month difference to allow some time for FERC approval after BoT adoption in an attempt to more or less put the effective dates of the two groups of entities in the same general time frame. The implementation plan as presented will always result in an effective date for the non-jurisdictional entities to be at least some months (the time between BoT adoption and FERC approval) earlier than their jurisdictional counterparts.
No
(1) We do not agree with the High VRF for R3 which asks for implementing the maintenance plan (and initiate corrective measures) whose development and content requirements (R1 and R2) themselves have a Medium VRF. Failure to develop a maintenance program with the attributes specified in R1, and stipulation of the maintenance intervals or performance criteria as required in R2, will render R3 not executable. Hence, we suggest that the VRF for R3 be changed to Medium. (2) The Severe VSL for R2 is improper. First, the reference to R3 is incorrect. Second, the first condition that says: “Failed to establish the entire technical justification described within R3 for the initial use of the performance-based PSMP” introduces a requirement not stipulated in R2 itself. We suggest to remove this condition. If the SDT feels strongly that the technical justification (we’re not sure what exactly it is) needs to be established for the initial use of the performance-based PSMP, then R2 should be revised to capture this requirement.
Individual
Martin Kaufman
ExxonMobil Research and Engineering
No
No
No
Yes
The SDT should provide notes that reference the sources used for developing the maximum maintenance intervals utilized in the time-based program, and provide a technical explanation as to why they have not provided a tolerance band for use with the time-based program. What is the increase in risk owned by an entity when a protective device is tested at the 6 year and 30 day mark instead of the 6 year mark?
PRC-005-2 is a highly prescriptive standard that prevents small entities from establishing a risk-based approach to protective system maintenance that is commonly used in other industry sectors and forces the small entity to utilize the time-based program. Many registered entities do not have a

population size of 60 for each type of protective device. However, they do possess historical records that can be used to calculate the mean time between failures for each equipment type that adequately reflects the service conditions in which the equipment is installed. The SDT should consider allowing registered entities to utilize historical records in their supporting documentation for defining a performance based program. Additionally, by restricting populations by manufacturer model, as referenced in PRC-005-2 Attachment A, the Standard Drafting Team is bordering on anti-competitive behavior as those entities that utilize performance-based programs may be discouraged to utilize alternative suppliers because utilization of a time-based maintenance program on the alternative supplier's equipment may present a cost-benefit analysis hurdle that the supplier of the equipment is not able to overcome. Lastly, the SDT has chosen not to provide a tolerance band for the maximum maintenance intervals it defines in its time-base program. Given that the SDT has not provided sound technical justification (i.e. a study, industry recommended practice, etc.), the SDT should reconsider its stance on providing a tolerance band on the time intervals specified in the time-based program. What is the increase in risk owned by an entity when a protective device is tested at the 6 year and 30 day mark instead of the 6 year mark?
Individual
Gary Kruempel
MidAmerican Energy Company
Yes
Yes
In the background section of the implementation plan in item two it states "...it is unrealistic for those entities to be immediately in compliance with the new intervals." Recent compliance application notices indicate that auditors are requiring entities to include proof of compliance to maintenance intervals by providing the most recent and prior maintenance dates. The implementation document could be improved by providing clarity to what is expected with regard to when an entity is expected to provide evidence of maintenance interval compliance given the quoted item above. As an example in the section the implementation plan for a 6 year interval item it states: " The entity shall be at least 30% compliant on the first day of the first calendar quarter 3 years following applicable regulatory approval.." In keeping with the previously quoted "reasonableness" criteria it would seem that 30% compliant would mean only one test action would be needed to be completed by the indicated deadline and the next one would be required no later than 6 years from that first test. It is recommended that the implementation plan document be improved to clarify this issue. In addition, it would seem appropriate to allow entities that decide to implement PRC-005-2 requirements before the standard becomes effective to count the maintenance they do before the effective date in the implementation plan schedule and in the testing interval compliance.
Yes
No
Requirement R3 of the standard discusses resolution of "identified maintenance correctable issues". M3 requires evidence of "resolution of Maintenance Correctable Issues". The definition of Maintenance Correctable Issue in the standard includes "during performance of the initial on-site activity". The "initial on-site activity" seems to imply that the corrective steps that need to be tracked are those resulting from the periodic testing that is done for compliance with the standard. It is not clear if the SDT meant to require that records be kept of any required maintenance that is done as a result of a discovered problem or failure that is not identified during the periodic testing.
Individual
Alice Ireland
Xcel Energy
Yes
Regarding the last row of Table 1-4(f): it seems very inconsistent to require a formal trending program for a manual 6 month(VRLA)/18 month (VLA) internal ohmic reading but to require no gathering and analysis of data as an alarm for a ohmic value for each cell/unit is available. If just a raw ohmic value is an adequate predictor of cell life, than why require a trending program for the

manual reading if all that is needed to determine adequacy of remaining cell life is just a simple acceptance criteria (i.e. - alarm setpoint) against which you need to compare your measured data? In theory these are very gradual and predictable changes in ohmic readings over the entire life of the battery, such that the benefit of real time knowledge of exactly when a threshold is reached via alarm is minimal rather than having to wait until the next manual reading to ascertain that the threshold limit has been reached.
Yes
Yes
Yes
1) On page 65, paragraph 4, of the “Supplemental reference and FAQ” document, it states: “… the type of test equipment used to establish the baseline must be used for any future trending of the cells internal ohmic measurements because of variances in test equipment and the type of ohmic measurement used by different manufacturer’s equipment.” While we understand the importance of creating a baseline, it is not feasible to expect the test equipment be the same as the manufacturer’s test equipment or even the same test equipment over the life of the battery. The expected life of a battery may be in excess of 20 years and it is not feasible to expect that the type of test equipment will not change during this period. 2) A FAQ to clarify in scope protection systems for variable energy resource facilities (wind, solar, etc) would be very helpful. Does paragraph 4.2.5.3 “Facilities” imply that the only protection system associated with a wind farm that is considered in scope for PRC-005-2 is that for the aggregating transformer? If other protection systems associated with a wind farm are in scope, please clarify which systems would be in scope for PRC-005-2. For example, a typical wind farm in our system might have 30-33, 1.5MVA windmills connected to one 34.5 KV collecting feeder circuit for a total of roughly 50 MVA per collecting feeder. 4 of these 50 MVA collecting feeders are tied via circuit breakers to a low side 34.5 KV bus which in turn is connected via a low side breaker to aggregating step up transformer which then connects to the BES transmission system. Obviously per paragraph 4.2.5.3, the protection system for the aggregating step up transformer is in scope. What about the protection system for the transformer low side 34.5 KV breaker – serving 200 MVA of aggregate generation? What about the protection system of each individual 34.5 KV aggregating feeder – 50 MVA of aggregate generation? What about the “protection system” for each individual 1.5 MVA windmill? An FAQ on this topic would be very helpful.
1) Regarding “Facilities” paragraph 4.2.5, we are in agreement with the elimination from scope of system connected station service transformers for those plants that are normally fed from a generator connected station service transformers. However, in the cases where a plant does not have a generator connected station service transformer such that it is normally fed from a system connected station service transformer, is it still the drafting team’s intent to exclude the protection systems for these system connected auxiliary transformers from scope even when the loss of the normal (system connected) station service transformer will result in a trip of a BES generating facility? If the end result of the trip of the primary station service transformer is a trip of a BES generating facility, it would be more consistent to include the protection system for that transformer as in scope – whether it be connected to the system or to the generator. 2) We recommend the SDT consider an interval of 12 calendar years for the component in row 3, of Table 1-5 on page 19 of the standard. The maximum maintenance interval for “Electromechanical lockout and/or tripping devices which are directly in a trip path from the protective relay to the interrupting device trip coil” should be consistent with the “Unmonitored control circuit” interval which is 12 calendar years. In order to test the lockout relays, it may be necessary to take a bus outage (due to lack of redundancy and associated stability issues with delayed clearing). Increasing the frequency of bus outages (with associated lines or transformers) will also increase the amount of time that the BES is in a less intact system configuration. Increasing the time the BES is in a less intact system configuration also increases the probability of a low frequency, high impact event occurring. Therefore, the Maximum Maintenance Interval should be 12 years for lockout relays. We believe that, as written, the testing of “each” trip coil and the proposed maintenance interval for lockout testing will result in the increased amount of time that the BES is in a less intact system configuration. We hope that the SDT will consider these changes.