Individual or group. (50 Responses)
Name (29 Responses)
Organization (29 Responses)
Group Name (21 Responses)
Lead Contact (21 Responses)
Question 1 (47 Responses)
Question 1 Comments (50 Responses)
Question 2 (42 Responses)
Question 2 Comments (50 Responses)
Question 3 (41 Responses)
Question 3 Comments (50 Responses)
Question 4 (46 Responses)
Question 4 Comments (50 Responses)
Question 5 (41 Responses)
Question 5 Comments (50 Responses)
Question 6 (0 Responses)
Question 6 Comments (50 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Yes
Maintenance and testing of protection systems is the final step in the process that begins with the calculation of settings. The calculation of settings is followed by the application of those settings to the equipment. Maintenance and testing ensures that the settings given to testing personnel have been applied as given. This Standard addresses the Maintenance and Testing of protection systems. It should also address the need to validate the accuracy of the settings given to the field. A statement should be added to the SAR to address this need.
The focus of the industry is on the field procedures necessary to ensure that protection systems are maintained and tested. This includes the verification that settings have been applied correctly. The accuracy of the settings calculated needs to be validated, and that step should be considered for inclusion in this Standard.
Group
Northeast Power Coordinating Council
Guy Zito
No
Yes
Yes
Yes
Yes
The focus of the industry is on the field procedures necessary to ensure that protection systems are maintained and tested. This includes the verification that settings have been applied correctly. The accuracy of the settings produced needs to be validated, and that step should be considered for

inclusion in this Standard.
Group
Northeast Power Coordinating Council
Guy Zito
The focus of the industry is on the field procedures necessary to ensure that protection systems are maintained and tested. This includes the verification that settings have been applied correctly. The accuracy of the settings calculated needs to be validated, and that step should be considered for inclusion in this Standard.
Group
Arizona Public Service Company
Janet Smith, Regulaory Compliance Supervisor
No
Yes
No
APS has been testing batteries nominally every 4 months plus 25% for over 20 years with no adverse consequences. Requiring a maximum of testing every 4 months doesn't allow for any flexibility, would require an additioal 400 tests per year and APS does not consider the 4 months a maximum time limit for battery testing.
Yes
While we are supportive of the changes the SDT has made, APS is concerned the draft Standard will not give entities the flexibility to continue to improve reliability based on changing industry norms and best practices. In addition, when technology changes for the better, industry will need the flexibility to optimize use of the new technology. Lastly, the more often protection equipment is taken out of service for testing, the more often the line is vulnerable. The balance between the correct amount of testing and correct amount of time the equipment is in the field and in service is an important consideration when assuring the reliability of the BES. APS suggests the general principles of the following two papers be applied to more equipment types than microprocessor relays with self test capabilities. 1) 'An Improved Model for Protective-System Reliability,' P.M. Anderson and S.K. Agrawal, Power Math Associates, Inc., IEEE Transactions on Reliability, Volume 41, No. 3, September 1992; 2) 'Philosophies for Testing Protective Relays,' J.J. Kumm, et. al., Schweitzer Engineering Laboratory, Inc., 48th Annual Georgia Tech Protective Relaying Conference, May 1994.
Individual
Mary Jo Cooper
ZGlobal Engineering and Energy Solutions
Yes
Table 1-4(a-c) excludes distributed UFLS and UVLS for batteries but references Table 3. Table 3 does not mention an interval for batteries. Is this an error?

Group
Southern Company Generation
Bill Shultz
No
No
The measures associated with the requirement that includes this term is non-specific with regards to what an auditor will require as proof of the initiation of resolving the issue. It is suggested that one of these two courses be followed: either a) eliminate the requirement to initate resolution, or b) fully describe what evidence is expected for this part.
Yes
Yes
1) Separating this classification of equipment into its own table is a good idea to make it easier for the owners of this equipment to figure out what they must do. 2) Consider also moving the UVLS note (found in column 1 of Tables 1-4a-d) into the header with the other "UFLS and UVLS note" to simplify the table. The header note could read "Excludes UFLS and UVLS systems - see Table 1-4e for non-distributed UFLS and UVLS systems and see Table 3 for distributed UFLS and UVLS systems"). 3) Table 1-5: Need clarification on "continuity and energization or ability to operate". What does this mean? 4) For UF and UV schemes, Table 3 does not specifically state to check the alarm(s) to a control center (for monitored components). There are some references to Table 2 (i.e. See Table 2), but does that mean that you have to verify the alarm(s)? We think that the Table 2 details need to be included specifically in Table 3. Or, make it very clear that this test is required for UF and UV schemes.
No
Several additional edits are needed so that the document matches the proposed standard: 1) In Section 5.1.1, page 16, add "and Table 3" in the Figure and at the end of FAQ after figure in that section. 2) In Section 7.1, example #1, a 3 month battery interval is shown 3) In Section 8.1.1, a 3 month interval is shown for communication circuit 4) In Section 15.5.1, several references to "3 month" and "three month" intervals are shown for communication circuits. 5) In Appendix B, the formatting is incorrect for Al McMeekin's company name.
1) For Table 1-1 and Table 3, consider adding "(internal to the relay)" to the microprocessor relay 6 calendar year maintenance activities to clarify that these maintenance activities are not related to items external to the relay).
Individual
Nicholas R. Finney
Saft America, Inc.
Yes
Yes
Yes
Yes
Yes
Saft Comments on NERC Standard PRC-005-2 — Protection System Maintenance Please find herein Saft's comments to NERC PRC-005-2 regarding ohmic testing of Nickel-Cadmium (NiCad) batteries. As drafted, the proposed NERC Standard PRC-005-2 will lead to the removal of high quality, reliable NiCad battery power units from Protection Systems, which is counter to the NERC stated purpose of PRC-005-2, which is to 'document and implement programs for the maintenance of all Protection

Systems affecting the reliability of the Bulk Electric System (BES) so that these Protection Systems are kept in working order.' There is broad consensus within the battery industry that ohmic testing of Valve Regulated Lead-Acid (VRLA) batteries provides a means for trending the condition of the battery over time. Such a consensus does not exist for Vented Lead-Acid (VLA) batteries, because ohmic measurements are more difficult to trend, thereby providing a go/no-go assessment of the battery's availability at that precise moment in time, rather than a measure of VLA battery condition. Ohmic testing of NiCad batteries provides a similar go/no-go assessment to ohmic testing of VLA batteries. As with VLA batteries, ohmic testing of NiCad batteries does not provide meaningful trending information, but rather provides a status update of battery condition at a specific moment in time. Due to the similar information provided by ohmic testing of VLA and NiCad batteries, Saft recommends that ohmic testing of NiCad batteries be included under the Maintenance Activities for NiCad batteries. Specifically, Saft recommends that NERC add the following language to the Maintenance Activities column in Table 1-4(d), 'Verify that the station battery can perform as designed by evaluating the measured cell/unit internal ohmic values to station battery baseline', at a maximum maintenance interval of 18 months, as in the requirement for VLA batteries noted in Table 1-4(a).
Group
Westar Energy
Bo Jones
No
Yes
Yes
Yes
Yes
Individual
Tony Eddleman
Nebraska Public Power District
No
Yes
Yes
We agree 4 calendar months is better than 3 Calendar months. The 4 month activities should be removed from Tables 1-4(a,b,c,d). These requirements are blurring the distinction between a best practice and functionally verifying the component. IEEE already sets the industries best practices, if a reliability Standard includes best maintenance practices it is encroaching on IEEE's ability to keep the industry informed and optimized. The Standard Drafting Team should restrain itself to only making requirements that functionally verify components and initiate corrective action wherever possible.
Yes
No
a. On page 26 of the Supplementary Reference document, it states, "If your PSMP (plan) requires more activities than you must perform and document to this higher standard." This penalizes utilities from including best practices in their PSMP, and encourages utilities to implement the standard maintenance practice instead of a higher maintenance practice. Why would a utility accept the additional risk of a NERC penalty or sanction when they can stay in compliance by accepting the

minimum requirements of the standard? By stating this, the PSMP will include only those required items at the minimum frequency to avoid a compliance violation. For the reliability of the BES, recommend the wording be changed to, "If your PSMP (plan) requires more activities than required by PRC-005-2, you will be held accountable only to the minimum requirements in the standard. NERC encourages utilities to implement best practices to improve the reliability of the BES, so utilities will not be penalized for exceeding the standards." In FERC Order 693, section 278 FERC states: While we appreciate that many entities may perform at a higher level than that required by the Reliability Standards, and commend them for doing so, the Commission is focused on what is required under the Reliability Standards, we do not require that they exceed the Reliability Standards".
a. Section 4.2.5.4 includes station service transformers for generator facilities. As currently written, the section includes all the protection systems for station service transformers for generators that are a part of the BES. It states, "Protection Systems for generator-connected station service transformers for generators that are part of the BES." Generating facilities may have transfer schemes on the auxiliary transformer to transfer equipment to a reserve transformer instead of tripping the unit. These protection systems should not be included in the Facilities for PRC-005-2, since the BES is not affected. Recommend changing Section 4.2.5.4 to read, "Protection Systems that trip the generator for generator-connected station service transformers for generators that are a part of the BES." b. Section 1.3 requires an entity to retain the two most recent performances of each distinct maintenance activity. This is an unreasonable requirement and does not enhance reliability. Recommend the data retention be changed to require only the most recent test record. An audit should be focused on the present day and not in the past. Is an entity compliant today and not can we find a way to issue a fine for something in the past? An example exists where an entity recently registered and tested all their relays prior to registering. They have one set of documentation and not two. Why should they be forced into testing again and incurring additional expense for customers only to have two tests available for an auditor? This does not enhance reliability. PRC-005-2 allows testing intervals of up to 12 calendar years. If we are required to have the two most recent tests, we could conceivably have to retain a relay test record for 24 years! Hypothetically, if we have a test record from ten years ago, but we don't have the record from 24 years ago, how does that adversely affect the reliability of the BES today? The standard should focus on – Are we compliant today? c. Table 1-5 requires a maintenance activity to, "Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Recommend this be changed to, "Verify that a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Or alternately, change the wording to, "Electrically operate each interrupting device every 6 years." While requiring each trip coil to operate the breaker sounds good in theory, practically it creates issues in the field and may create more problems than it solves. The trip coils are located in the panel at the breaker and aren't configured to test independently. Isolating one trip coil from the other may include "lifting a wire" that may not get landed properly when the test is complete. Then, how do you prove for a compliance audit that both trip coils were independently tested to trip the breaker? Using an actual event only tests one coil and we may not know which coil tripped the device. To be compliant, it isn't practical to be able to track a real-time fault clearing operation as suggested on page 67 of the Supplementary Reference document. First, we don't know which trip coil operated, then we have a "one off" device in the substation that must be tracked separately with a different testing cycle from the other devices in the substation – this is a recipe for a compliance violation. The standard should focus on ensuring the control circuitry is intact and trips the breaker without injecting additional, unneeded risk to the BES. d. General comment under Table 1-5: We do extensive testing of the control circuit during commissioning and after a modification to the circuit. Testing of the control circuitry on a periodic basis is not needed. The wear and tear on the equipment from functional testing and the potential risk of the testing itself may create more issues than the benefits received from doing the tests. The functional test injects significant opportunities for human performance errors during the test (technician trips the wrong device, differential relay opens all protective devices for a bus instead of a breaker, technician bumps another relay, screw driver falls into another device, etc.) and latent errors after the test (i.e., if a wire was lifted during the test, was it landed back in proper location, was the relay tripping function activated after the test was completed or was the relay left in test mode, etc.). Request the drafting team provide a basis for requiring the functional test. Are there documented instances where the control circuitry caused a significant event on the BES? Many utilities, including us, monitor our circuit breakers for operations. If a breaker hasn't operated for a defined period of time, we set up a maintenance activity to operate the breaker (possibly to include a timing test to ensure the breaker clears in the proper amount of cycles) – this ensures the operating linkages aren't

bound and the breaker will operate. We have many maintenance activities performed on devices for the BES that do not require a NERC standard. If a utility chooses not to perform best practice maintenance, customers will experience more frequent and longer outages. The utility will receive customer feedback on outages which should translate into the utility increasing its maintenance. In other words, we don't have to include a functional test as a NERC requirement. Misoperations are already monitored and reported through PRC-004. Does recent misoperation data or TADS data indicate that control circuitry/trip coils are a problem within the protection and control system? The current version of PRC-005 doesn't require functional tests. What is the basis for requiring additional compliance documentation (additional functional testing)? A possible alternative: only perform testing following modifications or major maintenance (like breaker change outs or panel modifications). e. Recommend NERC provide training specifically on how to audit PRC-005-2 to auditors in all eight Regional Entities. PRC-005 is the most violated standard since enforcement began on June 18, 2007. This is an excellent opportunity for NERC to get all eight regions on the same page for what to audit. NERC provides training on standard auditing guidelines and sample selection, but doesn't provide training on how to audit specific standards. RSAW's and CAN's have been an attempt to get consistency across the regions, but differences are still obvious. NERC is in the perfect position to observe potential violations (PV) from an auditor and as a PV is written that goes beyond the standard or is not in accordance with the initial training; NERC can dismiss the PV and retrain the auditor. Auditors aren't perfect, nor are any of us. Training is a basic tool for the auditor to perform their job properly.
Individual
John Bee
Exelon
No
Yes
Yes
Yes
Yes
Individual
Don Jones
Texas Reliability Entity
No
Yes
(1) General – defined terms need to be capitalized throughout this standard. (2) Requirement R3 only addresses initiation of resolution to any Unresolved Maintenance Issues. Requirement R3 should require completion of corrective action to deal with Unresolved Maintenance Issues within a reasonable timeframe. (3) Section 1.3, Data Retention, should require each entity to keep all versions of its PSMP that were in effect since its last compliance audit, in order to demonstrate compliance at all relevant times (not just the current version). (4) In the Severe VSL for R2, add "Annually" to the second bullet under part 5. (5) The VSLs for R3 should contain a time frame (annual?). The second part of these VSLs should refer to initiation and completion of resolution of Unresolved Maintenance Issues. (See comment on Requirement R3 above.) (6) Consider making the R3 VSLs based on a

percent of the number of maintenance activities required by the PSMP in a stated time period, rather than on a percent of the total number of Components. (7) There is no maintenance activity listed to verify that protection system component settings meet the design intent of the protection system. In other words, there is no required activity to confirm that the “specified” settings are correct and appropriate. This introduces a potential reliability gap into the Protection System maintenance program. (8) In Table 1-1, the term “acceptable measurement of power system input values” is somewhat vague. A tolerance value or reference to industry standards should be provided. (9) In Table 1-3, the activity should include verifying that the current and voltage signal values are within design tolerances, not just that signal values are present. (10) In Table 1-4(a) Component Attributes – the reference to UFLS systems is missing in the exclusion that refers to UVLS systems. (UFLS is included in Tables 1-4(b) through 1-4(d).) (11) In table 1-4(f), there should be a reference to “alarming” in addition to “monitoring” in the first cell of the next-to-last row. (12) In table 1-4(f), why is the last row limited to VRLA station batteries? Should the same exclusion apply to VLA batteries? (13) In Table 1-5, a “12 calendar year” interval is too long for “Unmonitored control circuitry associated with SPS” and “Unmonitored control circuitry associated with protective functions.” We suggest this be changed to 6 years. Similar unmonitored attributes related to battery maintenance have a 6 calendar year interval. (14) In Table 2, the phrase “location where corrective action can be initiated” is unclear, and we suggest that a more definitive description be used. Also, why is the word “DETECTION” in all-caps? (15) In Table 3, the maintenance activity should include verifying that Protection System Component settings meet the design intent of the Protection System. For example, any reclosing function should be disabled on UFLS and UVLS relay systems. (16) In Table 3, In Table 1-1, the term “acceptable measurement of power system input values” is somewhat vague. A tolerance value or reference to industry standards should be provided. (17) The Implementation Plan is overly long and complicated. Entities (including Regional Entities) will have to track and apply multiple versions of this standard for 14 years. It would be preferable to have a much shorter implementation plan, so that only one version of the standard will be applicable, recognizing that for some Components no action will be required under the standard for a number of years.
Individual
Steve Alexanderson
Central Lincoln
No
Either term works if defined properly.
Yes
Thank you for making this change. As we pointed out in draft 2, a three month maximum would require a bi-monthly target to allow for contingencies; increasing maintenance from four times a year (per the IEEE battery standards) to six.
Yes
Yes
We are concerned about what exactly “initiate resolution” means in R3. We foresee this being a potential area of disagreement between registrants and CEAs when a registrant believes an open work order suffices and the CEA wants to see schedules or purchase orders. Neither M3 nor the FAQs address this.
Group
Tennessee Valley Authority
Dave Davidson
No
No
No

No
No
1. It will take several years for TVA to implement checkback on 590 carrier blocking sets on the TVA system and not have to perform the PRC 005-2 requirement of verifying functionality every 4 months with no grace period. TVA carrier failure rate has not increased since the frequency was changed in January 2008 from 4 tests/year to 2 test/year. We are also implementing an extensive PM test in October 2011 which will test 25% of the sets per year and will take readings of SWR, line loss, and receiver margin. 2. TVA disagrees with the requirement to measure internal ohmic values of the station dc supply batteries every 18 months. The interval should be 36 months. Our experience from performing our routine maintenance program including cell impedance testing at 3-year intervals has been that the program is fully adequate in monitoring bank condition. An 18-month interval for internal resistance/impedance testing is an unnecessary burden. 3. Are we required to test the trip circuit between the power transformer sudden pressure relay and the switch house or are we only required to test the trip circuit between the electrical sensing relays and the trip coils of the breakers?
Individual
Dan Roethemeyer
Dynegy Inc.
No
Yes
Yes
Yes
Yes
For Facilities listed under 4.2, are Reserve Auxiliary Transformers supposed to be included?
Group
PNGC Comment Group
Ron Sporseen
No
No
Yes
We agree with this change. Smaller utilities, especially in the WECC region, in many cases have large territories to cover with limited resources. In many instances sub-stations are inaccesible during the winter and the 4 month interval will assist these smaller entities in getting the work done.
Yes
Thank you for the opportunity to comment on the draft Standard PRC-005-2 – Protection System Maintenance. While the feedback from the last round of comments is appreciated, we still cannot support the standard as written due to our concerns outlined here. We appreciate the work that NERC has put into a new standard to encapsulate and replace the current PRC-005, PRC-008, PRC-011 and PRC-017. But, we believe that the draft Standard needs one important revision before the NERC Board of Trustees should approve it. Specifically, NERC should revise the draft version of PRC-005-2

so that the beginning of Section 4.2 reads as follows: “4.2. Facilities: Protection Systems that (1) are not facilities used in the local distribution of electricity, (2) are facilities and control systems necessary for operating an interconnected electric energy transmission network, and (3) are any of the following:” This revision is necessary to capture the limits that Congress placed on FERC, NERC, and the Regional Entities in developing and enforcing mandatory reliability standards. Specifically, Section 215(i) of the Federal Power Act provides that the Electric Reliability Organization (ERO) “shall have authority to develop and enforce compliance with reliability standards for only the Bulk-Power System.” And, Section 215(a)(1) of the statute defines the term “Bulk-Power System” or “BPS” as: (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.” With this language, Congress expressly limited FERC, NERC, and the Regional Entities’ jurisdiction with regard to local distribution facilities as well as those facilities not necessary for operating a transmission network. Given that these facilities are statutorily excluded from the definition of the BPS, reliability standards may not be developed or enforced for facilities used in local distribution. In Order No. 672, FERC adopted the statutory definition of the BPS. In Order No. 743-A, issued earlier this year, the Commission acknowledged that “Congress has specifically exempted ‘facilities used in the local distribution of electric energy’” from the BPS definition. FERC also held that to the extent any facility is a facility used in the local distribution of electric energy, it is exempted from the requirements of Section 215. In Order No. 743-A, FERC delegated to NERC the task of proposing for FERC approval criteria and a process to identify the facilities used in local distribution that will be excluded from NERC and FERC regulation. The critical first step in this process is for NERC to propose criteria for approval by FERC to determine which facilities are used in local distribution, and are therefore not BPS facilities. The criteria to be developed by NERC must exclude any facilities that are used in the local distribution of electric energy, because all such facilities are beyond the scope of the statutory definition of the BPS, which establishes the limit of FERC and NERC jurisdiction. Accordingly, it is critical that NERC draft the new PRC-005-2 standard to expressly exclude facilities used in local distribution. NERC must also expressly exclude from PRC-005-2 those facilities “not necessary for operating an interconnected electric energy transmission network (or any portion thereof)”. Similar to the local distribution exclusion, the facilities not necessary for operating a transmission network are not part of the BPS and therefore must be expressly excluded from the standard. We understand, but disagree with, the argument that, because the FPA clearly excludes local distribution facilities and facilities necessary for operating an interconnected electric transmission network from FERC, NERC, and Regional Entity jurisdiction, it is not necessary to expressly exclude these facilities again in reliability standards. This approach might be legally accurate, but could lead to significant confusion for entities attempting to implement the new PRC-005-2 standard. There are numerous examples of Regional Entities, particularly WECC, attempting to assert jurisdiction over such facilities, and regulated entities face significant uncertainty as to which facilities they should consider as within jurisdiction. Clarifying FERC, NERC, and Regional Entity jurisdiction in the BES definition, even if such clarification is already provided in the FPA, would avoid such problems under the new PRC-005-2 standard. Again, we appreciate the work NERC has put in so far on a new Standard. We look forward to working within the drafting process to help implement our recommended revision.
Individual
Thad Ness
American Electric Power
No
The definition’s wording is satisfactory, and we agree with the removal of “failure of a component to operate within design parameters”. However, we do not agree with the use of the word “unresolved” within the term itself, as we believe this word may convey that the issue was not known or identified. We suggest replacing “Unresolved Maintenance Issue” with “Corrective Maintenance Issue”.
No
Though we agree with extending the interval from what it was previously, AEP recommends that the interval in Table 1-2 for Communications Systems be increased to 6 months.
Yes

No
With such a complex standard as this, the FAQ and Supplementary Reference documents do aid the Protection System owner in demystifying the requirements. However, AEP is uncertain how much weight the documents might carry during audits. We recommend that this additional information be included within the actual standard (for example in an appendix) but in a more compact version. Section 15.7 of the supplementary reference includes the bullet point “No verification of trip path required between the lock-out and/or auxiliary tripping device(s).” This appears to contradict the other bullet points within Section 15.7.
As it stands, if an entity adopts a more stringent maintenance program but fails to meet it, that entity could be found non-compliant despite continuing to abide by the minimum requirements of the standard itself. Entities should have the ability, if they so choose, to include additional maintenance activities or more stringent intervals than specified within the standard without concern of penalty in the event they are unable to accomplish them. In short, entities should only be audited against the requirements stated within the standard. Table 1-3 of the standard lists the minimum required maintenance activities for voltage and current sensing devices as "Verify that current and voltage signal values are provided to the protective relay." Consistent with Table 1-3, Section 15.2.1 of the Supplementary Reference states that an entity “...must verify that the protective relay is receiving the expected values from the voltage and current sensing devices...” The Supplementary Reference further offers examples of how this requirement may be satisfied with most examples referencing the need to verify the signal at each relay in the circuit. We recognize the need to verify a voltage signal at each protective relay, as these devices are wired in parallel and an open circuit at one location may not impact the other devices on the circuit. However, we do not agree that there is a need to verify a current signal at each protective relay. Current devices are wired in series, and an open circuit at any location will impact all other devices on the circuit. For this reason, a single measurement of the current circuit is sufficient. We recommend updating Table 1-3 and the supplementary reference to account for the different physical characteristics of voltage and current circuits. This standard encompasses a very broad range of component types and functionality across broad segments of the BES. The proposed VSLs and VRFs place the same level of severity or priority on facilities that serve local load with that of an EHV facility. The percentages indicated in the VSLs seem to be too strict based upon the vast quantity of elements in scope and broad range of application. Other standards have applicability for certain thresholds of voltage levels, etc. Why not this standard as well?
Individual
Eric Ruskamp
Lincoln Electric System
No
Yes
Yes
Yes
No
Please see the comments submitted by the MRO NSRF.
In reference to the zero tolerance policy evident within PRC-005-2, LES offers the following suggestion: Set up an annual review of a random set sample (20% for example) of Protection System equipment to self-verify compliance. If issues arise, allow the entity the opportunity to correct the issue, make the necessary procedural and/or documentation adjustments and not be considered non-compliant. The idea is to allow entities the opportunity to continually improve their practices and procedures; in essence, allow them to show they are attempting to follow a “culture of compliance”. If habitual problems arise, then non-compliance will be evident. One example that justifies this approach is software glitches or improper programming. As more and more systems become automated, scheduling of maintenance will be done automatically through various types of software.

If a program has even one attribute set incorrectly, it could not function as intended and would potentially set up incorrect intervals for maintenance and testing. It was not intended this way by the entity and they are not intentionally disregarding the standards, but could nevertheless be put in a situation where a maintenance interval is missed. An annual review would catch things like this and allow an entity to continuously improve their program without self-reporting. This concept is expanded from a current draft version of several CIP standards; therefore, it is being at least considered by other drafting teams.
Group
Tacoma Power
Max Emrick
No
Yes
Yes
A similar change in interval should be applied to intervals of “6 calendar months".
Yes
Yes
It is not clear to what extent can an entity (or auditor) can rely on information contained within the Supplementary Reference to support their position during an audit. There is a disclaimer at the beginning of the Supplementary Reference stating that “this supplementary reference to PRC-005-2 is neither mandatory nor enforceable.” It seems that interpretation of the draft standard depends heavily upon this Supplementary Reference. At the same time, the Supplementary Reference does not rise to the level of a standard.
1. The implementation plan for R2 and R3 is unclear on whether each maintenance activity has its own implementation schedule. The implementation plan can also be interpreted to mean that the implementation schedule for a given protection system component is driven by the smallest maximum maintenance (allowable) interval. For example, for unmonitored communications systems, it is unclear whether all maintenance activities indicated in Table 1-2, including those corresponding to 6 calendar years, must be completed on all unmonitored communications systems by the first calendar quarter 15 months following applicable regulatory approval, or if this timeline only applies to the maintenance activity specified in Table 1-2 corresponding to a maximum maintenance interval of 4 calendar months. 2. Assuming that there is a different implementation schedule for different maintenance activities for some protection system component types (namely station DC supply and communication systems), the middle bullet on page 1 of the implementation plan does not seem to consider that it may not be possible to identify whether some protection system components are completely being addressed by PRC-005-2 or the Program developed for the previous standards. In other words, during implementation, some maintenance activities for the same protection system component may be addressed by PRC-005-2, while other maintenance activities may be addressed by the Program develoepd for the previous standards. 3. It is unclear whether control circuitry (trip paths) from protective relays that respond to mechanical quantities is included. This issue is addressed in the supplementary reference but is vague in the draft standard itself. 4. This draft of PRC-005-2 requires the Protection System Maintenance Program (PSMP) to “include all applicable monitoring attributes and related maintenance activities” per the Tables and requires an entity to “implement and follow its PSMP.” Under the draft standard, it is unclear whether an entity has to document in the PSMP and/or maintenance records how they accomplish(ed) the maintenance activities or simply to indicate that the maintenance activities are included and have been completed within the defined intervals. It is clear that entities are afforded some latitude in how they conduct the required maintenance activities. However, the level of detail required to document (1) how an entity chooses to perform the maintenance activities and (2) that applicable maintenance activities have been completed is not clear. 5. In Table 1-2, there is a maintenance activity related to communication systems to “verify essential signals to and from other Protection System components.” It is unclear if this statement is referring to control circuitry associated with the communication system end devices, end device input and output operation (as in Table 1-1 for protective relays), or

something else. It is recommended that the requirement be to “verify operation of communictation system inputs and outputs that are essential to proper functioning of the Protection System.” This language is consistent with that used for protective relays in Table 1-1. 6. Referring to Table 1-2, it is unclear whether an entity has the sole authority decide which ‘performance critera’ are ‘pertinent.’ Additionally, it is unclear if an entity must document the ‘communications technology applied’ and the associated ‘performance criteria’ in its PSMP. 7. In Table 1-4, it is unclear if there is a distinction between the terms ‘resistance’ and ‘ohmic values.’ If there is a distinction, then this distinction should be clarified. 8. In Table 1-4, it is unclear if there is a distinction between the terms ‘battery terminal connection resistance’ and ‘unit-to-unit connection resistance.’ If there is a distinction, then this distinction should be clarified. 9. In Table 1-4, replace the term ‘resistance’ with ‘impedance.’ 10. Recommend that the 6 calendar month interval in Table 1-4(b) be lengthened to 18 calendar months to be more consistent with similar maintenance activities for other battery types. At minimum, lengthen the interval to at least 7 calendar months in a similar way that 3 calendar months was lengthened to 4 calendar months for other maintenance activities. 11. Referring to Table 1-5, no periodic maintenance is required for “control circuitry whose continuity and energization or ability to operate are monitored and alarmed.” It is unclear whether or not it is acceptable to verify DC voltage at the actuating device trip terminals at least once every 12 calendar years for “unmonitored control circuitry associated with protective functions.” It is recommended that periodically verifying DC voltage in this manner be an acceptable means of accomplishing the maintenance activity identified in Table 1-5 for unmonitored control circuitry associated with protective functions. 12. Referring to 4.2. Facilities of the draft standard, it is unclear whether protection systems for transformers that step down from over 100kV to below 15kV are applicable to the standard. Even if there are normally-open distribution feeder ties for purposes of transferring load in a make-before-break fashion, these transformers are generally not considered BES elements. 13. Referring to 4.2.5 of the draft standard, it is unclear whether protection for generator excitation systems are applicable to the standard. 14. It is unclear whether external timing relays (e.g., Zone 2) are considered control circuitry components (like lockout and auxiliary relays) or protective relay components.
Individual
Joe O'Brien
NIPSCO
No
The new standard itself, the implementation plan and supplemental reference/FAQ makes up more than 100 pages of material. Granted that several standards are being combined here, still it is simply too involved to monitor. And there is still not enough detail in the standard leaving items which are ambiguous and open to interpretation, and therefore open to fines. In order to remove such interpretation, maintenance documentation will need to be precise and extensive. This will necessitate more and more staff to control and validate data. Adding staff is great but it does not seem to ensure that there is increased reliability.
Individual
Edward Davis
Entergy Services
No
Yes
Yes
Yes

Yes
We understand and disagree with the SDT position on the following recommendation. We do not agree with proposed Section 4.2.1 applicability since it captures only a portion of the previously approved applicability Interpretation (PRC-005-1a) which was developed specifically for PRC-005-1. We suggest the draft standard be revised to conform to the wording in the Interpretation: “Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.) and trips an interrupting device that interrupts current supplied directly from the BES Elements.”
Group
Bonneville Power Administration
Chris Higgins
No
No
BPA agrees that the term “Maintenance Correctable Issue” is an improvement over “Unresolved Maintenance Issue”, however, BPA feels that the idea of a “Maintenance Correctable Issue” is very vague, and would perhaps be better left out of the standard. As written, it is unclear when an issue is a “Maintenance Correctable Issue” and exactly how it has to be dealt with. R3 requires the initiation of resolution of any unresolved maintenance issues.
Yes
Yes
Yes
BPA understands that the VSLs for R3 are based on the percentage of unresolved maintenance issues that an entity has failed to initiate a resolution for. This approach penalizes an entity for having less unresolved maintenance issues. For example, if an entity has only one unresolved maintenance issue and it failed to initiate a resolution for it, it would have failed to initiate a resolution for 100% of its unresolved maintenance issues, which would be a severe VSL. If another entity had 100 unresolved maintenance issues, and it failed to initiate resolution on ten of them, it would have failed to initiate a resolution on 10% of its unresolved maintenance issues, which would be a high VSL. Most likely, the first entity is doing a better job with its maintenance than the second entity, but the first entity receives a more severe penalty. The VSL for R3 is not an accurate measurement of a maintenance program’s effectiveness and needs to be revised. BPA recommends removing the entire “Unresolved Maintenance Issue” topic from the standard. In Table 1-1, it is not clear when a microprocessor relay meets the requirement for internal self-diagnosis and alarming. It is not clear that any microprocessor relay with a relay failure alarm would meet this requirement. BPA believes that it seems like an omission in Table 1-1 for unmonitored microprocessor relays, the verification of settings is not included as a maintenance activity. BPA would also like to recommend clarifying language stating that the owner of the asset is the responsible entity.
Group
Progress Energy
Jim Eckelkamp
No
Yes
Yes

Yes
• Standard, Table 1-4(a), second sentence under Component Attributes, should state “Protection System Station dc supply for non-BES interrupting devices for SPS or non-distributed UFLS and UVLS systems are excluded….” As written, the statement does not include the phrase “UFLS and.” I believe it should. • Supplemental, Section 13, 2nd paragraph, first sentence should state: “...device match the minimum requirements listed in Tables 1 and 3.”
Individual
Michael Falvo
Independent Electricity System Operator
No
Yes
The IESO agrees with the revision to the term. However, we observed the inconsistent format of this defined term used throughout the draft standard and would like to point it out to the Drafting Team. The capitalized term “Unresolved Maintenance Issue” is defined on Page 2 and used as a capitalized term in the blue box on Page 5. The defined term was made lowercase and used in other areas of the document as “unresolved maintenance issues” (eg. Page 5 and Page 8). We recommend that the format of this defined term be consistent throughout the draft standard.
Yes
Yes
Yes
The IESO disagrees with the concept that auditors use the standards as minimum requirements and evaluate compliance based on a registered entity’s own governance. We believe that the entity could be found non-compliant with Requirement R3 if they fail to follow the internal maintenance intervals established in their PSMP, even though actual maintenance intervals are no less frequent than the prescribed maximum intervals established in the draft standard. The potential for such a finding will discourage conscientious entities from setting higher internal targets for their planned maintenance and promote compliance with only the minimum requirements of the standard. We therefore propose the following revision to Requirement R3: R3. Each Transmission Owner, Generator Owner, and Distribution Provider shall implement and follow its PSMP and initiate resolution of any unresolved maintenance issues. In the case of time-based maintenance programs, each Transmission Owner, Generator Owner, and Distribution Provider is permitted to deviate from its PSMP provided that actual maintenance intervals do not exceed those specified in Tables 1-1 through 1-5, Table 2 and Table 3. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
Individual
Daniel Duff
Liberty Electric Power LLC
No
Yes
Yes
Yes
No
The reference contains language which makes it a violation should an entity choose a cycle time less than the maximum from the table, and then fail to meet that cycle. (see page 27, "If your PSMP

(plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard.") There is no reason to hold a RE in violation if all work is performed within the maximum time from the table - either there was no reliability risk, or the table is incorrect and a reliability risk in itself.
With the development and publication of maximum maintenance and testing intervals (the Tables), there is no longer a reliability need for a RE to identify the associated maintenance intervals for Protection System Components. Further, REs who wish to perform these activities in shorter intervals than those allowed by the standard (See Supplementary Reference, page 27,"If your PSMP (plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard.")As noted in Question 5, if the entity completes all activities within the maximum interval allowed by the standard, there can be no reliability concern; if there is a reliability issue, then the table interval is incorrect. I would suggest the following changes. 1. Change R1.2 to read "Identify any Protection System component where the RE is using a performance based maintenance interval. No batteries associated with the station DC supply component type of Protection System shall be included in a performance based system". 2. Change R1.3 to read "The intervals for time-based programs are established in Table 1-1 through 1-5, Table 2, and Table 3". 3. Change M1 to add the phrase "for performance-based components" after the words "maintenance intervals". 4. In M1, replace the words "the type of maintenance program applied (time-based, performance based, or a combination of these maintenance methods)' with the words "the identification of any protection system components using performance based intervals".
Group
Dominion
Mike Garton
No
Yes
Yes
Yes
Yes
Individual
Kirit Shah
Ameren
No
Yes
Yes
Our experience with a very large number of communication systems and station dc supplies substantiates an even longer interval as sufficient for reliable Protection Systems.
Yes
Please consistently state UFLS before UVLS; Table 1-4(e) differs from other parts of the standard.
Yes
1) Although the explanation of ‘Restore’ is enlightening on page 12, ‘Restore’ no longer appears in the PS Maintenance definition in the last few drafts. We disagree with the added burden of retaining maintenance records for removed or replaced equipment. This will actually reduce reliability because of the confusion it can cause as to what equipment is providing BES protection. At most, only the last maintenance date of the removed or replaced component should be retained if there’s really a need to

prove that the interval was met regarding the BES protection. 2) Remove ‘Reverse power relays’ from the list on page 32. They provide thermal of the steam turbine, not electrical protection of the generator.
(1)Measure M3 on page 5 should only apply to 99.5% of the components. Please revise to state: “Each … shall have evidence that it has implemented the Protection System Maintenance Program for 99.5% of its components and initiated….” PRC-005-2 unrealistically mandates perfection without providing technical justification. A basic premise of engineering is to allow for reasonable tolerances, even Six Sigma allows for defects. Requiring perfection may well harm reliability by distracting valuable resources from higher priority duties concerning the Protection System. We are not asking for the VSL to be changed. No one is perfect and it is impractical to imply perfection is achievable. The consequence of a very small number of components having a missed or late maintenance activity is insignificant to BES reliability. Our proposed reasonable tolerance sets an appropriate level of performance expectation. We disagree with the notion that this is “non-performance”.(2)2. An alternate approach regarding the unrealistic perfection of M3 is to correctly recognize that the protection of the primary BES is the objective. Most Protection Systems are redundant by design and the entity needs to be afforded the opportunity to show that a redundant component met the PSMP thereby providing the required protection. The entity should be allowed a reasonable time frame of one calendar increment to maintain the component in question. Our concern stems from the tens of thousands of components in a PSMP, and the reality that rarely but occasionally a data base error or outage scheduling issue may result in a very small number component exceeding their maximum interval. As long as the entity can show that BES protection was sustained and maintains the component quickly (e.g. within one calendar month of discovery), BES reliability has been maintained. (3) Now that FERC has approved the Project 2009-17 Interpretation, please acknowledge more directly in the Supplement that the ‘transmission Protection System’ that is now approved. NERC interprets “transmission Protection System,” as it appears in Requirements R1 and R3 of PRC-004-1 and Requirements R1 and R2 of PRC-005-1, to mean “any Protection System that is installed for the purpose of detecting faults on transmission elements (lines, buses, transformers, etc.) identified as being included in the Bulk Electric System (BES) and trips an interrupting device that interrupts current supplied directlyfrom the BES.”
Group
FirstEnergy
Sam Ciccone
No
Yes
Yes
Yes
No
We do not agree with aspects of the Supplementary Reference document as discussed in Question 6.
1. We remain concerned with the proposed draft version of Requirement R3 as well as the SDT developed statements in the Supplementary Reference & FAQ. The SDT's approach sends industry the wrong message; a message that entities should not go beyond what is in the text of the standards and that in some cases they can even be found non-compliant by failing to meet their own more stringent internal practice. We have sent NERC Staff and Drafting Team leaders a separate document detailing our concerns as well as proposed redlines to the standard. The separately provided document can be viewed as FE’s ballot comments. 2. FE supports the standard from a technical standpoint but offer the following additional comments and suggestions: A clarification to the supplementary reference document is necessary regarding Maintenance Activities specified for electromechanical lockout and/or tripping auxiliary devices, as specified in Table 1-5 of the standard. The standard states, “Verify electrical operation of electromechanical trip and auxiliary tripping devices” which must be performed every 6 years. A question was asked during the September 15th Webinar requesting clarification of what “verify electrical operation….” meant. The verbal response

from the SDT member was that this involves verifying that the relay actuates, but does not require verification that its contacts changed state. However, the answer to the question at the bottom of page 29 and top of page 30 in the Supplementary Reference and FAQ (dated July 29, 2011) implies that checking the contacts is necessary. The following statement in the published answer makes this clarification request necessary; “Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this Standard, to be checked.” This statement implies that if outputs to annunciators and DME inputs do not need to be checked, then the other outputs do need to be checked. Verification of the auxiliary tripping relays appears to be covered in Table 1-5 of the standard under the "Unmonitored control circuitry associated with protective functions" section at 12 calendar years. Thus, we ask the SDT clarify in the supplementary reference the type of maintenance activities required for electromechanical lockout and/or tripping auxiliary devices to satisfy the requirements of Table 1-5 of the standard. Since the standard specifically dictates the output contacts verification for protective relays under Table 1-1, the output contacts of aux tripping relays is left up to interpretation. Therefore, we suggest the following statement be added after “Auxiliary outputs not in a trip path (i.e. annunciation or DME input) are not required, by this Standard, to be checked.” on page 30 of the document: “Auxiliary outputs that are in the trip path shall be maintained as detailed in Table 1-5 of the standard under the ‘Unmonitored control circuitry associated with protective functions" section’ at 12 calendar years.”
Individual
Michael Lombardi
Northeast Utilities
No
Yes
Yes
Yes
The migration of the UFLS and UVLS requirements to Table 3 is appreciated. The Table 3 Component Attributes in rows 6 and 7 (“Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices” and Electromechanical lockout and/or tripping auxiliary devices associated only with UFLS or UVLS systems” respectively) do not identify that the trip coils are excluded. Although row 9 states “Trip coils of non-BES interrupting devices in UFLS or UVLS systems” do not have any period maintenance specified, our recommendation is to annotate rows 6 and 7 to explicitly indicate the trip coils are excluded.
Yes
1. The definition of “Component” in PRC-005-2 Draft 1, states “Another example of where the entity has some discretion on determining what constitutes a single component is the voltage and current sensing devices, where the entity may choose either to designate a full three-phase set of such devices or a single device as a single component.” However, in Section 15.2 of Supplementary Reference & FAQ it states: “The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.” Please consider reconciling these two sections (definition of “Component” and Section 15.2) to allow the entity to consider a relay as the single component versus the voltage and current sensing devices, and pursuant with Section 15.2 perform the voltage and current checks to the inventoried relays. This approach will ensure that the CT and PT check to each relay is performed. 2. Section 15.2 of Supplementary Reference & FAQ states in the second paragraph “The intent of the maintenance activity is to verify the input to the protective relay from the device that produces the current or voltage signal sample.” Please consider revising the last bullet in Section 15.2, paragraph 3 from “Any other method that provide documentation that the expected transformer values as applied to the inputs to the protective relays are acceptable” to “Any other method that verifies the input to the protective relay from the device that produces the current or voltage signal sample.” 3. As shown (see Figure A-2) and discussed in Appendix A of Supplementary Reference & FAQ list, there are four elements that are not verified. Following the identification of the four elements that are not verified, a

practical solution is provided for testing methods on three of the four elements. Please provide a practical solution for the fourth element.
Group
Southwest Power Pool Standards Review Group
Robert Rhodes
No
Yes
Yes
Yes
Yes
1. Please update Appendix B, Drafting Team Members, of the Supplementary Reference document. 2. We request that the detail for the breaker failure protection for generator protection in the bulleted list at the bottom of page 31 and the top of page 32 of the Supplementary Reference document be removed. We are not sure what the SDT is looking for here since there are several types of breaker failure protection. 3. We ask that Section 4.2.5.4 of the draft standard under the Facilities be modified to read 'Protection Systems that trip the generator for generator-connected station service transformers for generators that are part of the BES.' 4. We suggest that Section 1.3 Data Retention be rewritten to provide clarification that no data prior to the date of the last audit need be retained.
Individual
Gary Kruempel
MidAmerican Energy Company
No
Yes
Requirement R3 includes the following: “and initiate resolution of any unresolved maintenance issues”. For clarification it is recommended that the following change be made to this phrase: “initiate resolution of any unresolved Protection System maintenance issues”. Also it is recommended that the following be added to the list in M3: “work management system information”.
Yes
None
Yes
None
Yes
The changes to the “Supplementary Reference” document appear to be acceptable, but the following are suggested as changes to enhance clarity. On page 9 of the Supplementary Reference and FAQ draft the following statement is included: “Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.” On page 67, the third sentence of Section 15.3 states: “It includes [referring to control circuitry] the wiring from every trip output to every trip coil.” Later in that section the following is included: “...from a protective relay that are necessary for the correct operation of the protective functions.” While this later statement may be interpreted to exclude circuitry associated with relays that do not respond to non-electrical inputs or impulses it would be better to make this more explicit. It would seem illogical to require testing of circuitry that is not needed for the protective functions covered by the standard. It is suggested that a sentence like the following be added to the first paragraph of Section 15.3: “Control circuitry associated with relays that respond to non-electrical inputs or impulses is not covered by this standard and need not be tested.” On page 31 of the Supplementary Reference it indicates that a procedure that includes intervals less than the standard

could result in a noncompliance finding even if the maximum intervals in the standard are complied with. This is contrary to previous Commission rulings on what is mandatory and enforceable (i.e. only the standard itself Ref. Order 733 p105). This FAQ response should be changed to reflect those rulings.
The following comment was submitted in the last comment period: In the background section of the implementation plan in item two it states “..it is unrealistic for those entities to be immediately in compliance with the new intervals.” Recent compliance application notices indicate that auditors are requiring entities to include proof of compliance to maintenance intervals by providing the most recent and prior maintenance dates. The implementation document could be improved by providing clarity to what is expected with regard to when an entity is expected to provide evidence of maintenance interval compliance given the quoted item above. As an example in the section the implementation plan for a 6 year interval item it states: “ The entity shall be at least 30% compliant on the first day of the first calendar quarter 3 years following applicable regulatory approval..” In keeping with the previously quoted “reasonableness” criteria it would seem that 30% compliant would mean only one test action would be needed to be completed by the indicated deadline and the next one would be required no later than 6 years from that first test. It is recommended that the implementation plan document be improved to clarify this issue. The consideration of comments response to the above did not completely address the issue that led to the comment. In the Tables in PRC-005-2 there are maintenance items that an entity may not have had in their PRC-005-1 compliance program even though they did have a compliant maintenance program (e.g. battery continuity testing) for that Protection System component. As the transition is made to the PRC-005-2 requirement the above clarification should be made to better define what achievement of PRC-005-2 compliance is for that component. Section 4.2.2 includes UFLS systems installed per the ERO requirements - excluding any additional UFLS systems that a utility has on their system. Section 4.2.3 includes UVLS systems “installed to prevent system voltage collapse or voltage instability for BES reliability”. It is assumed that this would only include UVLS systems required by the ERO, but it is not clear as to what is in scope. It is suggested that the wording of 4.2.3 be changed to match the wording in 4.2.2. In the implementation plan in the R2 and R3 requirements plans, in item a. of each there is a parenthetical statement regarding generating plant scheduled outage intervals. A similar parenthetical statement should be added to the b. and c. items of each of these plans. The purpose statement of the standard seems to be inconsistent with the applicability section. To correct this it is suggested that the words “affecting the reliability” be removed from the purpose statement. For consistency with the changes from 3 months to 4 months in the tables of the standard it is suggested that the second item in Table 1-4(b) be changed from 6 calendar months to 7 calendar months. In the tables for dc Supply the term “unit-to-unit” is used along with “intercell” when referring to measurement of connection resistance. From the applicable IEEE standards (e.g. IEEE 450) the standard terminology seems to be “intercell”. It is recommended that the “unit-to-unit” term be removed to avoid confusion regarding what is to be verified.
Individual
Joe Petaski
Manitoba Hydro
No
Detailed Description: The phrase “Transmission & Generation Protection Systems” used in paragraph 1 should be “Transmission and generation Protection Systems”. “Transmission” and “Protection System” are defined words in the NERC Glossary of Terms; “Generation” is not a defined term and should not be capitalized. Applicable Reliability Principles: Is item 4 [Plans for emergency operation and system restoration of interconnected bulk electric systems shall be developed, coordinated, maintained and implemented.] applicable to Protection System Maintenance?
Yes
No
Manitoba Hydro maintains that the battery inspection interval should be extended to 6 months. The 4 month interval is too frequent based on our experience and while IEEE std 450 (which seems to be the basis for table 1-4) does recommend intervals, it also states that users should evaluate these recommendations against their own operating experience. Our experience shows that 6 month battery inspections are more than adequate to maintain system reliability. Manitoba Hydro has more than ten

years of experience using its existing battery inspection intervals, and Manitoba Hydro's reliability data has proven that the 6 month inspection interval is suitable for Manitoba Hydro. Manitoba Hydro's battery maintenance tasks were derived from a reliability study of Manitoba Hydro stationary batteries, and the tasks and intervals are suitable given Manitoba Hydro's installed plant, design criteria, climate, and reliability performance. A more frequent inspection interval might be more suitable to specific utilities with material differences in climate, design, installed apparatus, and performance, but it is not suitable for Manitoba Hydro and may be more than is required for many other utilities. To use a more frequent inspection interval would significantly penalize Manitoba Hydro which has been diligently performing battery inspections for many years, with no resulting increase in reliability. With the 4 month battery check frequency and no allowance for a grace period, there may be a negative impact on reliability caused by diverting resources away from projects that are critical to reliability to meet this maintenance interval.
Yes
No
Page 26: In both the industry webinar discussion and the supplementary reference document, it was indicated that if an entity had more maintenance activities in its plan than the minimum required by PRC-005-2, then an entity would be audited to the "higher standard". We understand that an entity could write some flexibility in its program, as long as the NERC minimums were met. We are concerned that auditing to the "higher standard" could discourage entities from performing maintenance tasks beyond the NERC minimum criteria. The discussion on page 9 indicates that although the relays which respond to mechanical parameters are not included in the scope of PRC-005-2, the associated trip circuits are included. We suggest that neither the relays which respond to mechanical parameters nor their associated trip circuits are within the scope of this standard. References to the tables should be consistently updated to include the new Table 3. "Every 3 calendar months" should be updated throughout the document to "Every 4 calendar months". For example, Page 23: Example #3 should be revised. In addition, there are a number of grammatical errors in the document, particularly capitalization and punctuation, which make it difficult to read. There are terms which are improperly capitalized implying that they are approved NERC Glossary of Terms definitions when they are not.
-Definition of Protection System Maintenance Program: The definition included in the proposed PRC-005-2 is not the same as the definition provided in the document "Definition for Approval", which also includes items "Upkeep" and "Restore". Regarding the words "proper operation of malfunctioning components is restored."; instead of focusing on the component, we suggest that the definition refer to the restoration of correct function, since some malfunctioning components will not be repairable and will need to be replaced. Although the supplementary document expands on the intended definition of "restore", this is not evident in the proposed stand-alone definition of Protection System Maintenance Program. Referring instead to restoration of proper Protection System function does not strictly require the restoration of a failed component. Suggested wording: Return the Protection System to correct function and proper operation. -We do not agree with the prescribed phased implementation plan. Entities should be given a single compliance date for each of the maintenance intervals, and be allowed the flexibility to schedule and complete their maintenance as required while transitioning to the defined time intervals in PRC-002-2. For example, if a maximum maintenance interval is 6 calendar years, the implementation plan should only require that "The entity shall be 100% compliant on the first day of the first calendar quarter 84 months following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required, on the first day of the first calendar quarter 96 months following Board of Trustees adoption." (item 4c.). The existing standard PRC-005-1 already requires protection systems to be maintained as part of a program. Prescribing how an entity must reach full compliance will provide a negligible improvement in reliability, while significantly increasing the compliance burden. PRC-005-2 affects a large number of assets, and proving compliance for prescribed percentages of assets during the transition period creates unnecessary overhead with no added value. We suggest that items 3a., 3b., 4a., 4b., 5a. and 5b be removed from the implementation plan. -Grace periods should be permitted on the maintenance time intervals. While we understand that grace periods can be built into a PSMP, maintenance decisions that compromise reliability may still have to be made just to meet the specified time intervals and avoid penalty. An example of this would be removing a hydraulic generator from service at a time of low reserve to meet a maintenance interval and avoid non-

compliance. Grace periods are also required in the case of extreme weather conditions. Such conditions may make it unsafe to perform maintenance within the maintenance interval (for example, performing a battery inspection at a remote station during severe winter weather) or may create a risk to reliability if the equipment being maintained is removed from service during these conditions. Utilities need to retain a reasonable amount of discretion and flexibility to make maintenance decisions that are best for safety and reliability without risking non-compliance. In addition, we disagree with the basis that the Drafting Team has established that grace periods are not permitted because of FERC Order 693 which requires that 'maximum' time intervals are established within PRC-005-2. With grace periods, a maximum time interval obviously becomes the required maintenance interval plus the maximum permitted grace period. So we strongly feel that grace periods can be added to the standard while adhering to the FERC Order. We also disagree with the line of reasoning that the Drafting Team used to establish the maximum maintenance intervals for relays as outlined on page 38 of the Supplementary Reference and FAQ document. To our knowledge, no document has been produced which provides evidence of maximum time intervals that work well for 'maintenance cycles that have been in use in generator plants for decades'. Our Protection Systems Maintenance experience indicates that the proposed intervals are acceptable as nominal time intervals with grace periods, but not as maximum time intervals without grace periods. Without a grace period, the bulk of protection maintenance on a six year maintenance cycle will have to be done one year earlier than previously required, in order to allow for the last year of the maximum interval to be used as the grace period. Manitoba Hydro considers this an unnecessary burden on resources with no benefit to reliability. Manitoba Hydro recommends that grace periods be permitted within PRC-005-2 if an entity can demonstrate a reliability or safety related need for using a grace period. This would require the Drafting Team to develop reliability-related criteria for using a grace period.
Individual
Andrew Z. Pusztai
American Transmission Company
No
Yes
Yes
Yes
No
ATC provides the following suggestions for change: Page 9, "Is a Sudden Pressure Relay an auxiliary tripping relay? " During the webinar on Thursday, September 15th it was asked whether the trip path for a sudden pressure relay needed to be confirmed. Based on this question, we believe that the FAQ should be modified as follows: Is a Sudden Pressure Relay an auxiliary tripping relay? No. IEEE C37.2-2008 assigns the device number 94 to auxiliary tripping relays. Sudden pressure relays are assigned device number 63. Sudden pressure relays are excluded from the Standard because it does not utilize voltage and/or current measurements to determine anomalies. Since the sudden pressure relay is not included, it also follows that trip path testing for this relay type is also excluded. Page 78, last paragraph: If the same type of ohmic testing is done (impedance, conductance or resistance), modify the FAQ to allow the use of a different manufacturer's test equipment to conduct the testing. Page 80, second paragraph: "The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning." Insert the following: "A reading taken from the battery charger panel meter will meet this requirement." "The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits." Insert the following. "A reading taken from the battery charger panel meter will meet this requirement."
a) Change the text of "Standard PRC-005-2 – Protection System Maintenance" Table 1-5 on page 19, Row 1, Column 3 to: "Verify that each a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Or alternatively, "Electrically operate each interrupting device every 6

years" Trip coils are designed to be energized no longer than the breaker opening time (3-5 cycles). They are robust devices that will successfully operate the breaker for 5,000-10,000 electrical operations. The most likely source of trip coil failure is the breaker operating mechanism binding, thereby preventing the breaker auxiliary stack from opening and keeping the trip coil energized for too long of a time period. Therefore, trip coil failure is a function of the breaker mechanism failure. Exercising the breakers and circuit switchers is an excellent practice. We would encourage language that would suggest this task be done every 2 years, not to exceed 3 years. Exercising the interrupting devices would help eliminate mechanism binding, reducing the chance that the trip coils are energized too long. The language as currently written in Table 1-5 row 1, will also have the unintentional effect of changing an entities existing interrupting device maintenance interval (essentially driving interrupting device testing to a less than 6 year cycle). b) Change the text of "Standard PRC-005-2 – Protection System Maintenance" Table 1-5 on page 19, Row 3, Column 2 to: "12 calendar years" The maximum maintenance interval for "Electromechanical lockout and/or tripping devices which are directly in a trip path from the protective relay to the interrupting device trip coil" should be consistent with the "Unmonitored control circuit" interval which is 12 calendar years. In order to test the lockout relays, it may be necessary to take a bus outage (due to lack of redundancy and associated stability issues with delayed clearing). Increasing the frequency of bus outages (with associated lines or transformers) will also increase the amount of time that the BES is in a less intact system configuration. Increasing the time the BES is in a less intact system configuration also increases the probability of a low frequency, high impact event occurring. Therefore, the Maximum Maintenance Interval should be 12 years for lockout relays. c)ATC's remaining concern for PRC-005-2 is with definition and timelines established in Table 1-5. ATC is recommending a negative ballot since, as written, the testing of "each" trip coil and the proposed maintenance interval for lockout testing will result in the increased amount of time that the BES is in a less intact system configuration. ATC hopes that the SDT will consider these changes.
Group
Florida Municipal Power Agency
Frank Gaffney
No
Yes
Yes
No
We like the new Table 3, but, have remaining concerns. The standard reaches further into the distribution system than we would like for UFLS and UVLS. We have two parts to this concern. First, it will be somewhat onerous to present all the evidence of distribution class protection system maintenance and testing at audits. And second, our biggest concern is in the testing required to "exercise" a lockout or tripping relay. This may require installation of test blocks to allow such exercising of the lockout or tripping relay without tripping the distribution circuit, and such a test could be difficult to perform without impacting customer continuity of service if the lockout/tripping relay for the UFLS is the same as the lockout/tripping relay for distribution fault protection. However, most of FMPA's members have microprocessor-based relays for distribution circuits with the UFLS / UVLS embedded within the microprocessor based relay where the path from the UFLS / UVLS relay to the lockout / tripping relay is internal to the micro-processor based relay, so, testing the UFLS/UVLS relay will at the same time test the internal lockout / switching relay. However, for older electro-mechanical UFLS schemes, this type of testing could be problematic.
The "Applicability" section is not consistent with the recent Y-W and Tri-State PRC-005 interpretation (Project 2009-17). The Applicability 4.2.1 states that the standard includes: "Protection Systems that are installed for the purpose of detecting faults on BES Elements (lines, buses, transformers, etc.)" whereas the Y-W and Tri-State interpretation basically says that "transmission Protection Systems" both detect AND trip BES Elements; Hence, the new standard alters the existing "and" statement in the Y-W and tri-State interpretation and eliminates the consideration of tripping BES Elements from

applicability. This will have the consequence of including Protection Systems on step-down transformers that "look backwards" into the BES system as applicable to the standard. For instance, a distribution network fed from multiple transmission interconnections will have protective relaying (directional overcurrent most likely) to look backwards into the transmission system to trip the step-down transformer to prevent back-feed from the distribution network). This step-down transformer protection would be included in the new standard because it's purpose to the detect faults on the BES (event though the purpose of the protection is actually to protect overloading of the distribution and for worker safety on the BES); whereas the Y-W and Tri-State interpretation excludes that protection from the existing PRC-005-1 standard.
Group
NERC Staff
Mallory Huggins
No
Yes
No
We agree in principle with the change; however, we have identified discrepancies among these tables with respect to the reference to UFLS and UVLS systems. The headings in Tables 1-1 through 1-4(b) and Table 1-5 refer to “Excluding distributed UFLS and UVLS”; Table 1-4(c) refers to “Excluding UFLS and non-distributed UVLS”; while Table 1-4(d) refers to “Excluding UFLS and distributed UVLS.” We believe the drafting team intended for consistency among these tables and that the intent is to exclude distributed UFLS and distributed UVLS schemes as opposed to distributed UFLS and all UVLS schemes. To make this clear we recommend changing the second line in the heading of each of these tables to “Excluding distributed UFLS and distributed UVLS.” Corresponding changes should be made in the “Component Attributes” sections of Tables 1-4(a) through 1-4(e) and to the title of Table 3.
No
We recommend changes to Supplementary Reference. It appears the 3 calendar month interval referenced in the second FAQ in section 7.1 on page 20, Example 1 on page 21, Example 2 on page 22, and on page 23 should be updated to 4 calendar months consistent with the changes to the standard for verification of station dc supply voltage and inspection of electrolyte level and unintentional grounds. We recommend modifying references to UFLS and UVLS to clarify the intervals for distributed systems applies to both UFLS and UVLS similar to the recommended change to the standard in our comment on question 4. See pp. 26, 30, 33, 86, and 87 of the supplementary reference.
Individual
Antonio Grayson
Southern Company Transmission
No
No
The measures associated with the requirement that includes this term is non-specific with regards to what an auditor will require as proof of the initiation of resolving the issue. It is suggested that one of these two courses be followed: either a) eliminate the requirement to initate resolution, or b) fully describe what evidence is expected for this part.
Yes
Yes
For UF and UV schemes, Table 3 does not specifically state to check the alarm(s) to a control center (for monitored components). There are some references to Table 2 (i.e. See Table 2), but does that mean that you have to verify the alarm(s)? I think Table 2 details need to be included specifically in

Table 3. Or make it very clear that this test is required for UF and UV schemes.
No
1. Page 16: ‘Add and Table 3’ in Figure and end of FAQ after figure 2. Page 20: change reference from 3 to 4 months. This applies throughout document.
Table 1-5: Need clarification on "continuity and energization or ability to operate". What does this mean?
Group
Pepco Holdings Inc & Affiliates
David Thorne
No
Yes
Yes
Yes
Yes
Requirement 3 and the Supplementary Reference Document indicate that an entity should be held to its internal PSMP (especially for a time based program) even if the plan is more stringent than the NERC standard. This would be a deterrent for initiative and for excellence and punish utilities for going above the standards and performing best practices. It also tends to drive the industry to lowest common denominator practices. R3 and the accompanying Supplementary Reference Document should be appropriately revised to reflect that entities would only be held auditably accountable for the minimum requirements as stated in the standard and associated documents.
Individual
Brian Evans-Mongeon
Utility Services, Inc
Yes
We would urge that the SAR be modified to include Validation of Protection System settings. Presently, the standard does not provide for the explicit validation of the settings and it is possible that such mis-settings could be the reason for a misoperation. If a validation of the settings was explicitly called for in the standard, then the misooperation would be less likely to occur for that reason.
Yes
While this helps, we are concerned that during the term of the Unresolved Maintenance Issue is being resolved, a question of compliance to the standard might be pending out. It should be clarified that during this term, compliance to the standard is being satisfied and not deemed to be non-compliant.
No
The standard should provide guidance what tasks need to be accomplished for compliance and not mandates on specifics like this. Registered Entities should be left to determine the appropriate intervals based upon their experience and good utility practices.
Yes
Thank you for the opportunity to address the new documentation and for your efforts.
Group
Western Area Power Administration
Brandy A. Dunn
No

Yes
Yes
Yes
No
See comments under question 6
Comment 1: Western Area Power Administration does not agree with penalizing utilities for implementing maintenance programs that exceed the requirements defined in the NERC Standard PRC-005-2 maintenance tables. Although the intent of the language in the Supplementary Reference and FAQ document may have been to allow evolving maintenance programs to include condition-based and performance based maintenance in their programs, penalizing utilities with more stringent programs will more likely provide a disincentive for program development. Utilities will discontinue any additional maintenance activities that could put them at risk for non-compliance. This will cause maintenance programs to stagnate and new maintenance ideas to improve system reliability to not be implemented. It is the opinion of the Western Area Power Administration that the following text should be removed from the Supplementary Reference and FAQ document and entities should be audited to the minimum requirement of the standard regardless of their individual programs. Recommendation: Remove the following text from the Supplementary Reference & FAQ document: 1. Page 26 - The bullet "If your PSMP (plan) requires more activities then you must perform and document to this higher standard." 2. Page 27 – The bullet "If your PSMP (plan) requires activities more often than the Tables maximum then you must perform and document those activities to your more stringent standard." 3. Page 27 – The paragraph "It has been noted here that an entity may have a PSMP that is more stringent than PRC-005-2. There may be any number of reasons that an entity chooses a more stringent plan than the minimums prescribed within PRC-005-2, most notable of which is an entity using performance based maintenance methodology. (Another reason for having a more stringent plan than is required could be a regional entity could have more stringent requirements.) Regardless of the rationale behind an entity's more stringent plan, it is incumbent upon them to perform the activities, and perform them at the stated intervals, of the entity's PSMP. A quality PSMP will help assure system reliability and adhering to any given PSMP should be the goal." Revise R3 of PRC-005-2 and add statement to the Supplementary Reference & FAQ document. 1. R3: Each Transmission Owner, Generator Owner and Distribution Provider shall implement and follow its PSMP plan within the prescribed intervals of Tables 1, 2 and 3. and correct any unresolved maintenance issues. 2. FAQ: Any utility maintaining Protection System equipment that exceeds the requirements and tables because of historical testing data and/or failure documentation should not be held non-compliant or penalized for not meeting its PSMP, as long as they do not exceed the maximum allowable intervals or meet the minimum maintenance activities of the standard. Comment 2: R3 of PRC-005-2 states "Each Transmission Owner, Generator Owner, and Distribution Provider shall implement and follow its PSMP and initiate resolution of any unresolved maintenance issues." The Western Area Power Administration would like more clarification on potential data request for requirement R3 of PRC-005-2. Because the requirement uses the term initiates resolution, the entity could make the assumption that providing just a list of maintenance request for unresolved maintenance issues will serve to prove compliance. Although it would seem implied that whatever method used to initiate resolution would lead to some type of corrective maintenance, the requirement does not make that absolutely clear. To ensure the maintenance practices are meeting the intent of the requirement, the requirement needs to clarify the expectations for completing corrective maintenance that was initiated to resolve maintenance issues. Recommendation: Add additional clarification to Supplementary Reference & FAQ document to further clarify expectation for this requirement.
Group
MRO's NERC Standards Review Forum
Carol Gerou
No

No
Requirement R3 includes the following: “and initiate resolution of any unresolved maintenance issues”. The addition of unresolved maintenance issues to the standard is not included in the SAR and has the potential to cause confusion and misinterpretation. It is suggested that this phrase be removed.
Yes
We agree 4 calendar months is better than 3 Calendar months. The 4 month activities should be removed from Tables 1-4(a,b,c,d). These requirements are blurring the distinction between a best practice and functionally verifying the component. IEEE already sets the industries best practices, if a reliability Standard includes best maintenance practices it is encroaching on IEEE’s ability to keep the industry informed and optimized. The Standard Drafting Team should restrain itself to only making requirements that functionally verify components and initiate corrective action wherever possible. We recommend that this time frame be a maximum of 6 Calendar Months which will allow entities to establish their own time frame based on the seasonal changes that occur where the batteries are located.
Yes
No
a. Page 9, “Is a Sudden Pressure Relay an auxiliary tripping relay? “ 1) During the webinar on Thursday, September 15th it was asked whether the trip path for a sudden pressure relay needed to be confirmed. Based on this question, we believe that the FAQ should be modified as follows: i. Is a Sudden Pressure Relay an auxiliary tripping relay? No. IEEE C37.2-2008 assigns the device number 94 to auxiliary tripping relays. Sudden pressure relays are assigned device number 63. Sudden pressure relays are excluded from the Standard because it does not utilize voltage and/or current measurements to determine anomalies. Since the sudden pressure relay is not included, it also follows that trip path testing for this relay type is also excluded. b. On page 26 of the Supplementary Reference document, it states, “If your PSMP (plan) requires more activities than you must perform and document to this higher standard.” This penalizes utilities from including best practices in their PSMP, and encourages utilities to implement the standard maintenance practice instead of a higher maintenance practice. Why would a utility accept the additional risk of a NERC penalty or sanction when they can stay in compliance by accepting the minimum requirements of the standard? By stating this, the PSMP will include only those required items at the minimum frequency to avoid a compliance violation. For the reliability of the BES, recommend the wording be changed to, “If your PSMP (plan) requires more activities than required by PRC-005-2, you will be held accountable only to the minimum requirements in the standard. NERC encourages utilities to implement best practices to improve the reliability of the BES, so utilities will not be penalized for exceeding the standards.” In FERC Order 693, section 278 FERC states: While we appreciate that many entities may perform at a higher level than that required by the Reliability Standards, and commend them for doing so, the Commission is focused on what is required under the Reliability Standards, we do not require that they exceed the Reliability Standards”. c. Page 78, last paragraph: If the same type of ohmic testing is done (impedance, conductance or resistance), may a different manufacturer’s test equipment be used for this testing? d. Page 79, second paragraph of “Why verify voltage?”: 1) “The verification of the dc supply voltage is simply an observation of battery voltage to prove that the charger has not been lost or is not malfunctioning.” i. Is it the intent of the PSMT SDT that this measurement is taken at the battery terminals, or will a reading taken from the battery charger panel meter meet this requirement? 2) “The maintenance activity of verifying the float voltage of the battery charger is not to prove that a charger is lost or producing high voltages on the station dc supply, but rather to prove that the charger is properly floating the battery within the proper voltage limits.” i. Is it the intent of the PSMT SDT that this measurement is taken at the battery terminals, or will a reading taken from the battery charger panel meter meet this requirement? e. Except as noted above, the changes to the “Supplementary Reference” document appear to be acceptable, but the following are suggested as changes to enhance clarity. 1) On page 9 of the Supplementary Reference and FAQ draft the following statement is included: “Relays that respond to non-electrical inputs or impulses (such as, but not limited to, vibration, pressure, seismic, thermal or gas accumulation) are not included.” On page 67, the third sentence of Section 15.3 states: “It includes [referring to control circuitry] the wiring from

every trip output to every trip coil." Later in that section the following is included: "...from a protective relay that are necessary for the correct operation of the protective functions." While this later statement may be interpreted to exclude circuitry associated with relays that do not respond to non-electrical inputs or impulses it would be better to make this more explicit. It would seem illogical to require testing of circuitry that is not needed for the protective functions covered by the standard. It is suggested that a sentence like the following be added to the first paragraph of Section 15.3: "Control circuitry associated with relays that respond to non-electrical inputs or impulses is not covered by this standard and need not be tested." 2) On page 31 of the Supplementary Reference it indicates that a procedure that includes intervals less than the standard could result in a noncompliance finding even if the maximum intervals in the standard are complied with. This is contrary to previous Commission rulings on what is mandatory and enforceable (i.e. only the standard itself Ref. Order 733 p105). This FAQ response should be changed to reflect those rulings.
a. Section 4.2.5.4 includes station service transformers for generator facilities. As currently written, the section includes all the protection systems for station service transformers for generators that are a part of the BES. It states, "Protection Systems for generator-connected station service transformers for generators that are part of the BES." Generating facilities may have transfer schemes on the auxiliary transformer to transfer equipment to a reserve transformer instead of tripping the unit. These protection systems should not be included in the Facilities for PRC-005-2, since the BES is not affected. Recommend changing Section 4.2.5.4 to read, "Protection Systems that trip the generator for generator-connected station service transformers for generators that are a part of the BES." b. Data Retention, Section 1.3 (concerning R2 and R3) requires an entity to retain the two most recent performances of each distinct maintenance activity. This is an unreasonable requirement and does not enhance reliability. Recommend the data retention be changed to require only the most recent (past) test record. An example exists where an entity recently registered and tested all their relays prior to registering. They have one set of documentation and not two. PRC-005-2 allows testing intervals of up to 12 calendar years. If we are required to have the two most recent tests, we could conceivably have to retain a relay test record for 24 years. Recommend retention to be the most current record or all records since the last audit. c. Table 1-5 requires a maintenance activity to, "Verify that each trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Recommend this be changed to, "Verify that each a trip coil is able to operate the circuit breaker, interrupting device, or mitigating device." Or alternately, change the wording to, "Electrically operate each interrupting device every 6 years." While requiring each trip coil to operate the breaker sounds good in theory, practically it creates issues in the field and may create more problems than it solves. The trip coils are located in the panel at the breaker and aren't configured to test independently. Isolating one trip coil from the other may include "lifting a wire" that may not get landed properly when the test is complete. Then, how do you prove for a compliance audit that both trip coils were independently tested to trip the breaker? Using an actual event only tests one coil and we may not know which coil tripped the device. To be compliant, it isn't practical to be able to track a real-time fault clearing operation as suggested on page 67 of the Supplementary Reference document. First, we don't know which trip coil operated, then we have a "one off" device in the substation that must be tracked separately with a different testing cycle from the other devices in the substation. The standard should focus on ensuring the control circuitry is intact and trips the breaker without injecting additional, unneeded risk to the BES. d. General comment under Table 1-5: We do extensive testing of the control circuit during commissioning and after a modification to the circuit. Testing of the control circuitry on a periodic basis is not needed. The wear and tear on the equipment from functional testing and the potential risk of the testing itself may create more issues than the benefits received from doing the tests. The functional test injects significant opportunities for human performance errors during the test (technician trips the wrong device, differential relay opens all protective devices for a bus instead of a breaker, technician bumps another relay, screw driver falls into another device, etc.) and latent errors after the test (i.e., if a wire was lifted during the test, was it landed back in proper location, was the relay tripping function activated after the test was completed or was the relay left in test mode, etc.). Request the drafting team provide a basis for requiring the functional test. Are there documented instances where the control circuitry caused a significant event on the BES? Many utilities, monitor circuit breakers for operations. If a breaker hasn't operated for a defined period of time, we set up a maintenance activity to operate the breaker (possibly to include a timing test to ensure the breaker clears in the proper amount of cycles) – this ensures the operating linkages aren't bound and the breaker will operate. Misoperations are already monitored and reported through PRC-004. Does recent misoperation data or TADS data indicate that control circuitry/trip coils are a

problem within the protection and control system? The current version of PRC-005 doesn't require functional tests. What is the basis for requiring additional compliance documentation (additional functional testing)? A possible alternative: only perform testing following modifications or major maintenance (like breaker change outs or panel modifications). e. Change the text of "Standard PRC-005-2 – Protection System Maintenance" Table 1-5 on page 19, Row 3, Column 2 to: "12 calendar years". 1) The maximum maintenance interval for "Electromechanical lockout and/or tripping devices which are directly in a trip path from the protective relay to the interrupting device trip coil" should be consistent with the "Unmonitored control circuit" interval which is 12 calendar years. 2) In order to test the lockout relays, it may be necessary to take a bus outage (due to lack of redundancy and associated stability issues with delayed clearing). Increasing the frequency of bus outages (with associated lines or transformers) will also increase the amount of time that the BES is in a less intact system configuration. Increasing the time the BES is in a less intact system configuration also increases the probability of a low frequency, high impact event occurring. Therefore, the Maximum Maintenance Interval should be 12 years for lockout relays. f. In the background section of the implementation plan in item two it states "..it is unrealistic for those entities to be immediately in compliance with the new intervals." A recent compliance application notice (CAN-0012) indicated that auditors are requiring entities to include proof of compliance to maintenance intervals by providing the most recent and prior maintenance dates. Please provide clarity on CAN-0012 is applicable to PRC-005-2? g. The purpose statement of the standard seems to be inconsistent with the applicability section. To correct this it is suggested that the words "affecting the reliability" be removed from the purpose statement. h. For consistency with the changes from 3 months to 4 months in the tables of the standard it is suggested that the second item in Table 1-4(b) be changed from 6 calendar months to 7 calendar months. i. In the tables for dc Supply the term "unit-to-unit" is used along with "intercell" when referring to measurement of connection resistance. From the applicable IEEE standards (e.g. IEEE 450) the standard terminology seems to be "intercell". It is recommended that the "unit-to-unit" term be removed to avoid confusion regarding what is to be verified. j. The NSRF would like to extend our thanks to the drafting team. The 96 page Supplementary Reference document allows us to discuss these issues before the standard is approved, instead of as a potential violation later. Excellent job!
Group
PacifiCorp
Sandra Shaffer
No
Yes
Yes
Yes
Yes
1. The data retention requirement for producing evidence that the entity performed maintenance for the 2 most recent maintenance intervals is excessive. As an example, if a registered entity's maintenance/test interval is 12 years, such entity may be required to keep records for up to 35 years. PacifiCorp recommends a revision to the data retention requirement to provide for either a maximum retention period of 10 years or, in cases in which the interval exceeds 10 years, the most recent maintenance/test cycle only. 2. The requirement to identify all PTs is very onerous and not needed to verify maintenance compliance and therefore serves a limited reliability benefit. PacifiCorp believes that, as long as a registered entity can demonstrate that it can verify that all CTs/PTs providing input into a Protection System have been tested and maintained according to its established procedures, then a separate and independent requirement to maintain a list of these devices is not necessary. As an example, if an entity performed their protection system maintenance on a "scheme" basis, and as part of that maintenance documentation identified all CT's and PT's providing input into the scheme and verified their accuracy, then having a "master list" would provide no benefit. A list of all CT's

associated with one device such as a circuit breaker would have little value in this case as these CT's may provide input into multiple relay schemes and would not be maintained on an individual circuit breaker basis.
Group
ACES Power Collaborators
Jason Marshall
No
Yes
Yes
Yes
No
There are some changes that are needed to the document. On Page 19, the second question refers to R1.4. There is no R1.4 in the standard. We assume that document is intended to refer to part 1.4 under R1. This needs to be clarified and corrected. The reference document creates an improper incentive to eliminate best practices and utilize the maximum time intervals established in the standard. The document states that an entity will be subject to compliance violations if it has a maintenance and testing program with time intervals that are more stringent than the maximum time intervals in the standard and it does not meet its more stringent intervals. This would hold true even if the registered entity meets the maximum intervals established in the standard. To reduce compliance risk, registered entities will be incented to increase its time intervals to the maximum allowed by the standard. This is contrary to supporting reliability. Penalizing entities for failing to meet their more stringent plan requirements is also contrary to guidance provided by the Commission. Doug Curry, General Counsel of Lincoln Electric System, spoke to the Commission at the November 18, 2010 FERC technical conference on reliability monitoring, enforcement and compliance about his company's experience with the vegetation management standard. They exceeded the requirements for annual inspections by including six aerial patrols each year but were found in violation of the standard and paid penalties when they did not complete but one aerial patrol in the first five months of the year. The auditors concluded that the company's ground patrol fully satisfied the minimum requirements of the standard. In the end, LES removed the aerial inspections from the vegetation management plan. The Commissioners acknowledged that this was contrary to their goal of an adequate level of reliability and agreed that an entity should not be penalized for failing to meet their more stringent requirements when they meet the standard requirements. On Page 34, the FAQ about commissioning does not appear to be consistent with CAN-0011. While we believe the reference document is more correct, the drafting team should compare the advice given in the reference document to that in the CAN to ensure that it is not conflicting. Given that NERC is in the process of revising all of the CANs, the best approach may simply be to add a statement referencing the CAN-0011 for further information. Comments about "gaming the PBM system" regarding restoring segment performance should be removed from the reference document. Comments like these indicate intent by a registered entity to manipulate the compliance process. Only after a thorough investigation can such intent be determined. Thus, there shouldn't be a presumption that registered entities will attempt this. Better comments would be to focus on the consistency that the three year period provides in determining segment performance. In section 12.1 on page 58, the reference document discusses out of service equipment. NERC recently issued a lesson learned on removing unused relaying equipment on August 10, 2011. The drafting team may wish to reference that lesson learned in the reference document.
Individual
Michael Moltane
ITC Holdings
No

Yes
Yes
Yes
Yes
ITC Holdings continues to object to the requirement to exercise auxiliary relays on a 6 year interval. We repeat our previous comments as follows: “It has been our experience that trip failures are rare and that our present 10 year control, trip tests, and other related testing are sufficient in verifying the integrity of the scheme. Section 8.3 of the Supplementary Reference notes statistical surveys were done to determine the maintenance intervals. Were auxiliary relays included in these surveys in a such a way to verify that they indeed require a 6 year maintenance interval? We recommend they be considered part of the control circuitry, with a 12 year test cycle.” Previous responses from the SDT were: “The SDT believes that the appropriate interval for electromechanical devices such as aux or lockout relays should remain at 6 years, as these devices contain “moving parts” which must be periodically exercised to remain reliable” ITC requests that the statistical basis for the 6 year interval be published. If it is not clear that lockout relays and other auxiliary relays must be exercised on a 6 year interval, then the requirement should be changed to 12 years.
Individual
Michelle D'Antuono
Igleside Cogeneration LP
No
Yes
The original term inferred that the problem detected was correctible through follow-up maintenance – which is not always the case. The term “Unresolved Maintenance Issue” is more appropriate.
Yes
Ingleside Cogeneration LP agrees that the intervals on the activities in question should be extended to 4 calendar months. However on Page 20 of the Supplementary Reference document, the calculation of the next due date using units of “calendar months” is inconsistent with the calculation using a “calendar year”. In the case of “calendar years”, an activity must take place somewhere between Jan 1 and Dec 31. For “four calendar months”, a follow-up activity must be performed within four months from the completion of the prior one. We believe that “four calendar months” should be calculated in the same manner as a “calendar year”. This means that an activity should take place at least once between January 1 and April 30; and repeated once during May 1 through August 31, and again between September 1 and December 31. The pattern would continue in ongoing years. Not only is this method consistent with the “calendar year” derivation, it allows the most flexibility in scheduling – especially if an unexpected event causes a delay. The vast majority of the maintenance activities will still take place at four months plus or minus a week or two; with an occasional outlier that adds minimal risk to reliability.
Yes
We believe that distributed UFLS and UVLS relay systems have a very different operating purpose than those that are not distributed. It is appropriate to separate the maintenance activities and intervals for these relay systems.
Yes
Ingleside Cogeneration LP found the Supplementary Reference document to be helpful, thorough, and technically accurate. The only suggestion we have is that demonstrated adherence to the Reference should be admissible of evidence of compliance at an audit or spot check. Today, all References have no official regulatory standing – which seems to defeat the purpose of developing them to begin with.
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.
Individual
Armin Klusman
CenterPoint Energy
No
For the “Control circuitry between the UFLS or UVLS relays and electromechanical lockout and/or tripping auxiliary devices”, the Table 3 requirement is to “Verify the path from the relay to the lockout and/or tripping auxiliary relay (including essential supervisory logic)” every 12 calendar years. CenterPoint Energy recommends this requirement be revised to “No periodic maintenance specified”. CenterPoint Energy believes that wire checking a panel is a commissioning task, not a preventive maintenance task. CenterPoint Energy performs such checks on new stations and whenever expansion or modification of existing stations dictates such testing. In addition, CenterPoint Energy recommends the requirement in Table 3 to “Verify that current and/or voltage signal values are provided to the protective relays” every 12 years be revised to “No periodic maintenance specified”. Likewise, we recommend the requirement in Table 3 to “Verify Protection System dc supply voltage” every 12 years be revised to “No periodic maintenance specified”. Preventive maintenance tasks such as the three above are unnecessary for distributed UFLS and UVLS system components. The overriding performance, or “risk-based”, NERC Reliability Standards for UFLS are PRC-006 and PRC-007 where an entity is required to shed their obligated firm load amount.
No
CenterPoint Energy appreciates that there is now only one document, instead of the two originally proposed. However, we question the name of the document which shows “Supplemental Reference and FAQ”. The use of “Supplemental Reference” could infer it contains requirements not found in the PRC-005-2 standard. Also, we suggest that NERC standardize on the names of documents associated with standards and other NERC initiatives. CenterPoint Energy recommends the name of the document be “Technical Reference”.
For the “Unmonitored control circuitry associated with protective functions”, the Table 1-5 requirement is to “Verify all paths of the trip circuits through the trip coil(s) of the circuit breakers or other interrupting devices” every 12 calendar years. CenterPoint Energy recommends this requirement be revised to “No periodic maintenance specified”. CenterPoint Energy believes that verifying all tripping paths is a commissioning task, not a preventive maintenance task. CenterPoint Energy performs such checks on new stations and whenever expansion or modification of existing stations dictates such testing. This type of testing can negatively impact BES system reliability with the outages that are required and by exposing the electric system to incorrect tripping. Likewise, CenterPoint Energy recommends the requirement in Table 1-5 to “Verify all paths of the control circuits essential for proper operation of the SPS” every 12 years be revised to “No periodic maintenance specified”.
Individual
Darryl Curtis
Oncor Electric Delivery Company LLC
No
Yes
Yes

Yes
Yes
Oncor would like to see the “Supplementary Reference & FAQ” expanded to provide examples of what documentation would satisfy that the entity is compliant with initiating “resolution of any unresolved maintenance issues.” Also it would be helpful to all entities if the Drafting Team would expand on what, if any, tracking of the resolution of an unresolved maintenance issue is required. Oncor believes that keeping track of the initiation of “resolution of any unresolved maintenance issues” is necessary but that the standard does not currently address retention requirements related to this compliance obligation.
PRC-005-2 is a vast improvement over the vagueness of the existing standard (PRC-005-1), that the new standard makes compliance much easier than the present standard. The new standard recognizes the advances in relay technology and reliability, particularly the benefits of microprocessor based relays. The standard also provides greater flexibility on its implementation while recognizing the benefits of a performance based methodology, particularly as it relates to battery testing. The revised standard eliminates the requirement for a “summary of maintenance and testing procedures” which was vague and provided no real value to the registered entities. Operational and administrative efficiencies can be realized by consolidating the relay testing and maintenance requirements into one standard (PRC-005-1, PRC-008-0, PRC-011-0, PRC-017-0)
Individual
Tracy Richardson
Springfield Utility Board
No
Yes
This change has no impact on how Springfield Utility Board currently operates.
Yes
This change has no impact on how Springfield Utility Board currently operates.
Yes
Although numerous tables can become overwhelming to navigate, it is far less ambiguous if specific systems are spelled out in separate and distinct tables.
Yes
Because Springfield Utility Board's (SUB) current maintenance and testing program is time-based, the revised "Supplementary Reference" document does not impact SUB operations. SUB agrees with the document changes because the changes result in alernatives for entitities, rather than being prescriptive.
Individual
Andrew Gallo
City of Austin dba Austin Energy
No
Yes
Yes
Yes
Yes
If a Registered Entity has a PSMP that is more stringent than the intervals in PRC-005-2, the

Registered Entity should not be considered out of compliance if it fails to meet its internal interval but remains within the interval set forth in PRC-005-2.
Individual
Gerry Schmitt
BGE
No
No comment.
No
No comment about the change itself, but the terms were not consistently applied in the Supplemental Reference Manual (see last comment).
Yes
BGE appreciates the SDT demonstrating flexibility by extending these maintenance intervals.
No
Although BGE does not disagree with moving the distributed UFLS/UVLS maintenance activities and intervals into the new Table-3, BGE requests further clarification from the SDT on how to correctly interpret the headings and content of this table.
No
While we do not disagree with the revisions to the Supplemental Reference, there remains an important item to correct. The supplementary reference on page 31, under the question beginning “Our maintenance plan calls…” states that an entity is “out of compliance” if maintenance occurs at a time longer than that specified in the entity’s plan, even if that maintenance occurred at less than the maximum interval in PRC-005-2. But then on page 35-36, under the question, “How do I achieve a grace period without being out of compliance?” the response provides a presumably compliant example of scheduling maintenance at four year intervals in order to manage scheduling complexities and assure completion in less than the maximum time of six calendar years. This advice conflicts with the previous guidance. The FAQ /supplementary reference should be revised so that it does not imply that an entity is out-of-compliance by performing maintenance more frequently than required than the bright-line maxima in the tables. Entities may opt to test more frequently than dictated in the tables for a variety of reasons that may or may not be related to reliable protection system performance – compliance management, scheduling, operational preference, etc.
When the term “Maintenance Correctable Issue” was revised to “Unresolved Maintenance Issue”, it appears that the PRC-005-2 Protection System Maintenance / Supplementary Reference and FAQ document was not properly updated to reflect this change. There are inconsistencies throughout the entire document were the old term is still showing up instead of the new term, and vice versa.
Individual
Amir Hammad
Constellation Power Generation
Yes
Although Constellation Power Generation agrees with some of the refinements prescribed in the SAR, there are a few items of concern. Constellation Power Generation agrees that “the requirements should reflect the inherent differences between various protection system technologies,” however the requirements should not mandate different testing methods and testing intervals based on that technology. The Registered Entity should be given the latitude to address different technologies through its PSMP, and the requirements should reflect that.
No
As R3 is currently written, Constellation Power Generation is concerned that this requirement may decrease the reliability of the BES under certain circumstances. The severity of the “deficiency” found will dictate the method and timing of a “follow up correction action”. For a generator, the corrective action may not be “initiated” until the next planned outage, which may be a few years. However, R3 suggests that to comply, a generation site may have to extend an outage or take a forced and unplanned outage, to perform the corrective action. This would decrease the available resources in a given BA’s footprint and potentially decrease the reliability of the BES.

No
Moving the UFLS and UVLS systems from Tables 1-1 through 1-5 into a separate Table 3 is a useful improvement in illustrating the requirements. However, our objection is not really with the format, it is will the content of the Tables. From a generation perspective, the maintenance intervals and activities described in all of the Tables are too prescriptive and we are concerned that they may conflict with the existing PSMPs built by Registered Entities based on years of operational experience with the testing methods and testing frequencies that work best for the specific asset. In the worst case, the specifics dictated in the Tables may move Entities away from more stringent PSMPs that are currently in practice. For this reason, Constellation suggests that the drafting team revisit the concept of the Tables to better balance to convey useful guidance without creating a compliance requirement that may be contrary to improved reliability. The Registered Entity should be given more flexibility to dictate how a protection system component should be tested, and at what frequency. Lastly, the technical manpower and compliance documentation demands to implement a performance based protection system maintenance program are so onerous that it is highly unlikely that any small generation entity would use it.
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Individual
Brenda Powell
Constellation Energy Commodities Group
Yes
Although Constellation Energy Commodities Group agrees with some of the refinements prescribed in the SAR, there are a few items of concern. Constellation Energy Commodities Group agrees that “the requirements should reflect the inherent differences between various protection system technologies,” however the requirements should not mandate different testing methods and testing intervals based on that technology. The Registered Entity should be given the latitude to address different technologies through its PSMP, and the requirements should reflect that.
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